68-01-5971

DEVELOPMENT OF PROCEDURES AND COSTS FOR PROPER ABANDONMENT AND PLUGGING OF INJECTION WELLS

Submitted to

Dr. Jentai Yang
Office of Drinking Water

Mr. Thomas F. Sullivan
Contract Operations

Prepared for the
U.S. Environmental Protection Agency

by

Booz, Allen and Hamilton Inc.

Under the Direction of

Geraghty & Miller, Inc.

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CHAPTER I

EXECUTIVE SUMMARY

I. EXECUTIVE SUMMARY

For your convenience, we have prepared this summary of data analysis and findings on proper abandonment and plugging. Our objective was to assist EPA in resolving issues raised in the public comments on the proposed abandonment regulations and in completing rule making. To achieve this objective, we reviewed the public comments and abandonment literature and conducted telephone and field interviews with operator and state representatives, surety companies, and well service companies. Exhibit I-1 summarizes the key questions, our principal findings, and recommendations.

1. PROCEDURES FOR PROPER ABANDONMENT

In response to public comments on the proposed requirements, EPA requested that we examine current state abandonment requirements and industry practice and evaluate the proposed requirement for achieving static equilibrium with the mud weight equalized top to bottom of the well.

(1) Current State Requirements[1]

Our examination of the regulations of 37 states showed substantial similarity among the states. All but Alaska and Nevada require the operator to inform the state of its intent to abandon and to receive approval of proposed plugging procedures. At least 49 percent require the operator to file a plugging affadavit or report. In addition, at least 38 percent either require or retain the option of having a state representative witness the abandonment. All states except Kentucky, Ohio, and Pennsylvania require cement plugs. The state requirements do vary with respect to the number and placement of plugs. Exhibit II-1 summarizes the state requirements, and Appendix A contains detailed information on the plug setting requirements of 13 states.

(2) Abandonment Procedures

Abandonment refers to the installation of mechanical and cement plugs at selected depths inside the well in order to prevent vertical migration of fluid. The procedures for Classes I, II, and III wells are similar,

[1] We reviewed regulations pertaining to [illegible]

EXHIBIT I-1
Principal Findings and Recommendations

KEY QUESTION	FINDING	RECOMMENDATION
What is the feasibility of EPA's proposed mud weight equalization requirement?	Establishment of static equilibrium with the mud weight equalized top to bottom is good engineering practice and essential to obtaining proper setting of cement plugs.	EPA should retain the requirement clarifying its applicability only to the well preparation phase of abandonment.
What is the feasibility of aquifer restoration?	Restoration based on water use appears possible while restoration to baseline does not; more efficient and economical techniques may emerge as operators have more experience with restoration.	EPA should not adopt a requirement for restoration; instead, it should issue technical guidance on restoration to the states and allow them to decide whether or not to adopt such a requirement.
What are the incremental costs of proposed abandonment requirements?	State abandonment requirements, other than financial responsibility ones, are applicable to at least 82% of Class I and 97% of Class II wells; only three states allow plugging materials other than cement; therefore, incremental costs, if any, will be low.	EPA need not revise the proposed regulations on the basis of incremental cost.
How will the proposed financial responsibility requirement affect operators?	Current Class II financial responsibility requirements in 84% of the 37 states examined cover only 47% of operations, since Kansas has no requirement and Texas has an optional one; therefore, the proposed regulation will pose a new obligation for some operators.	EPA should retain the financial responsibility requirement, allowing states to determine acceptable alternatives, thus reducing the potential cost impact on operators; EPA should issue technical guidance on the appropriate use of each alternative.
What is the need for immediate abandonment?	Excessive delay in abandonment promotes improper abandonment due to regulatory agency difficulty in tracking well location and status; however, premature abandonment can hinder mineral and energy production.	EPA should adopt the practice of some states in setting a time period within which operators must recommence operations or abandon the well.

consisting of well preparation and plug setting.*
Well preparation involves cleaning the well and establishing a mud system. Plugging involves either cementing the well top to bottom or setting various plugs. Only about 15 percent of all wells are cemented top to bottom. For the remaining wells, the better service companies typically use one of three methods:

- Balance Method
- Cement Retainer Method
- Two-Plug Method.

These methods, described in detail in the following chapter, vary in application according to the casing design and pressure characteristics of the formations influencing the well.

(3) Mud Weight Equalization

Achievement of static equilibrium of the mud with the weight equalized top to bottom is an essential step of the well preparation phase. Its objective is to prevent any contamination or breakup of the cement which would weaken it and result in a poor plug. Indicators of the achievement of static equilibrium are the exclusion from the well of fluids and gasses. Once plugging is completed, maintenance of static equilibrium is no longer necessary.

2. AQUIFER RESTORATION

In the preamble to the proposed regulations, EPA suggested aquifer restoration as one means for protecting underground sources of drinking water from contamination by Class III operations. Based on our review of current state and industry practice, we concluded that at the present time while restoration based on use is feasible, restoration to baseline probably is not. However, development of more efficient and economical restoration processes is likely.

(1) State Practice

We examined four states, Colorado, New Mexico, Texas, and Wyoming, which have the bulk of in-situ uranium sites and require aquifer restoration at those sites. Colorado and Texas have established restoration criteria on a project specific basis, whereas the other two states have different criteria based on water use. Exhibit III-1 summarizes these criteria.

* [illegible]

According to our data, aquifer restoration techniques have been applied only to in situ uranium operations. In the four states examined, all restoration projects have been pilot scale, and in most instances the restoration has occurred at the sites of pilot scale in situ uranium projects.

(2) Evaluation of Techniques

Three techniques proposed or tested on a pilot scale are:

- Pumping of selected leach field wells
- Pumping in combination with injection of various types of water
- Natural restoration.

Based on our examination of the case studies presented in detail in Appendix C, we found that pumping has been partially successful in achieving restoration based on water use. Pumping in combination with injection of natural groundwater has no particular advantage while injection of treated leach field water has been successful. The concept of natural restoration is untried.

3. ABANDONMENT COSTS

In order to complete its rule making record, EPA requested data and analysis on the unit and category costs of permitees abandoning wells in Classes I-III and on the extent to which these costs exceeded those associated with current state requirements. In addition, the agency requested data on the costs to operators of carrying out the proposed closure of all Class IV wells.

Our principal finding was that incremental costs are likely to be small since state regulations cover at least 82.8 percent of Class I and 97.4 percent of Class II wells. They are likely to occur only in those states which do not have a program or have an unacceptable program, or allow plugging materials other than cement. However, we also concluded, based on the detailed unit cost tables in Chapter IV and our review of the literature, that abandonment costs are only a small portion of the total cost of drilling, constructing, and operating a well. In addition, for Class IV, because of the lack of data on types and numbers of wells and volumes of waste, we prepared only partial unit cost estimates.*

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* The total unit costs would include those associated with alternative treatment/disposal methods.

Finally, without data on the projected rate of abandonment and the distribution of wells by depth and diameter, we were unable to calculate category costs in all four classes of wells.

4. FINANCIAL RESPONSIBILITY

Approximately 20 commenters expressed concern with the cost of obtaining individual well performance bonds in order to comply with EPA's proposed financial responsibility requirement. Accordingly, we identified four alternatives for demonstrating financial responsibility:

- Financial statements
- Performance bonds
- Escrow accounts
- Trust funds.

We identified current Class II requirements for 37 states and only limited data on Class I and III wells. Finally, we evaluated each option in terms of operator cost, ease of implementation, and effectiveness.

(1) State Requirements

Based on our limited analysis, we have concluded that in some states the Federal requirement may impose a significant new obligation on operators. The cost of this obligation will vary, as shown in Exhibit V-2, according to the option used for meeting the requirement. We found that although 84 percent of the states have a financial responsibility requirement for Class II wells, Texas and Kansas, two states with high concentrations of Class II wells, do not. However, Texas has the option to impose such requirements on a case-by-case basis. With respect to Class I and III operations, our limited data suggests that there are financial responsibility requirements, and that operators typically comply by securing a performance bond. A few states, such as Kansas, Oregon, Washington, and Wisconsin allow escrow accounts and trust funds, but these generally cover liability rather than performance.

(2) Evaluation of Alternatives

Of the four alternatives, performance bonds generally appear to be the most consistent with EPA's objective of promoting proper abandonment. The possibility of forfeiting collateral provides operators with an incentive to comply, and when noncompliance occurs, funds are available for proper abandonment. Since so many states currently require performance bonds and surety companies evaluate the operator's financial status, this option places little incremental burden on the manpower resources or technical capability of the regulatory agency. Finally, although it is higher in cost than financial statements, it is typically lower in cost than trust funds or escrow accounts. As Chapter V explains, the effectiveness of other alternatives apparently varies according to the wording of the state regulations and the vigilance of enforcement.

Our principal recommendation is that although performance bonds generally are more effective than other alternatives, EPA should not change its proposed regulations substantively to preclude the use of those alternatives. Rather, through technical guidance, EPA can inform its regional offices and the states of the operation and most effective application of each alternative.

5. TIMING OF ABANDONMENT

Industry is concerned that the proposed rules will require abandonment immediately upon cessation of operations and that such a requirement will lead to loss of assets. Although the regulations do not in fact pose such a requirement, in order to address this concern, we examined the advantages and disadvantages of immediate abandonment and developed and evaluated alternatives. Exhibits VI-1 and VI-2 summarize our analysis. Based on this analysis, our recommendation is that EPA adopt the practice of Kansas, Illinois, Michigan, Texas, and Utah by setting a maximum time period within which an operator must either recommence or abandon his well.

CHAPTER II

PROCEDURES FOR PROPER ABANDONMENT OF CLASS I-III INJECTION WELLS

II. PROCEDURES FOR PROPER ABANDONMENT OF CLASS I-III INJECTION WELLS

The proposed regulations for Class I-III wells require abandonment, according to procedures prescribed by the program director, which will preclude the migration of fluids into or between underground drinking water sources. In addition, the proposed regulations set a minimum requirement that the well "be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or a comparable method prescribed by the Director, prior to the placement of the cement plug(s)."

Commenters on the abandonment proposals did not understand the proposed requirements, particularly with respect to achieving static equilibrium and mud weight equalization. In order to complete its rulemaking, EPA requested a comprehensive description of current state and industry abandonment and plugging practices and an evaluation of the mud weight equalization requirement. Our first step in responding to EPA's request was to prepare a master list of all steps in the abandonment process and to review it with senior personnel from Halliburton Services, one of the major well service companies. Next, we reviewed the abandonment requirements of selected states as well as some of the literature on abandonment requirements. Based on our analysis of this data, the remainder of this chapter presents a description and evaluation of plugging methods, material and equipment used, and types of problems typically encountered.

1. SUMMARY OF STATE REQUIREMENTS

Although the general abandonment requirements are similar in most states, the specific requirements for plug type and setting methods vary considerably. Exhibit II-1 presents an overview of state requirements and Appendix A presents detailed plug setting requirements for 13 states. Of 37 states reviewed in varying detail,[1] all but Alaska and Nevada require

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1 Time limitations prevented a comprehensive and systematic data collection. For some states, we had current state statutes or regulations and one or more well [illegible]. For other states, we made extensive calls to state regulatory officials. Also, for Class II wells we utilized the summary of State Regulations prepared by the Interstate Oil Compact Commission. We found that, in general, requirements for Class I and III wells are [illegible] wells.

EXHIBIT II-1
Overview of State Abandonment Requirements

STATE	NOTICE OF INTENT	PLUGGING APPROVAL	TYPE PLUG	PROCEDURES SPECIFIED	REPORT OR AFFIDAVIT	REPRESENTATIVE PRESENT	% CLASS I (309)	% CLASS II (127,294)	% CLASS III (2000-8000)
Alabama	II	II		II	II		1.6	.1	TBS summarized the data on distribution of Class III practices by state (Table II-1, p. II-3) according to sites and did not state the number of wells at each site. Since estimates of Class III wells range from 2000 to 8000, it was not possible to determine the percentage currently covered by state regulations. Texas, which appears to have the highest concentration of Class III wells has abandonment requirements for those wells consistent with the ones for Classes I and II.
Alaska									
Arizona	II	II							
Arkansas	II	II						.7	
California	1,II	I,II	cement		1,II		1.3	10.9	
Colorado	II	II		II	II	II		0.5	
Florida	II	II						<.1	
Georgia	II	II							
Idaho	II	II							
Illinois	II	II	cement	II	II	II		8.2	
Indiana	II	(2)		II	II	II		1.4	
Kansas	II,III	•	cement	•	•	II,III	9.1	10.8	
Kentucky	II		(3)	II	II	II		6.3	
Louisiana	•	•	cement	•	•	•	21.0	2.0	
Maryland	II	II							
Michigan	•	•	cement	•	•		9.7	0.7	
Mississippi	II	II		II	II	II		0.8	
Missouri	II	II						.1	
Montana	II	II		II	II	II		0.6	
Nebraska	II	II						.2	
Nevada									
New Mexico	II,III	•		•	II,III		1.0	0.3	
New York	•	•	cement	•	III	•	1.6	0.3	
No. Carolina	II	II							
No. Dakota	II	II						.2	
Ohio	•	•	(4)	•	•	•	3.2	4.0	
Oklahoma	•	•	cement (5)	•	•	•	4.5	7.9	
Oregon	II	II							
Pennsylvania	•	•			•			1.8	
Tennessee	II	II							
Texas	•	•		•	•	•	27.5	37.0	
Utah	II	II		II	II			0.3	
Virginia	II	II							
Washington	II	II							
W. Virginia	•		(3)	•	•	•	2.3	0.1	
Wyoming	II	II		II	II	II		2.1	
Percentage							82.8	97.4	

(1) Several states have oil and gas regulations and are members of the Interstate Oil Compact Commission although the ADL report lists no Class II wells for those states.
(2) Dot-point denotes applicability to all three well classes.
(3) Cement or other seal approved by state
(4) Sediment, seasoned wood, lead, properly prepared clay, or cement.
(5) Cement, sand dumpings, or mud.

the operator to inform the state of its intent to plug and to receive approval prior to plugging.[1] At least 49 percent (18) require the operator to file an affadavit or report of plugging specifying the location, time, and method of plugging. In addition, at least 38 percent (14) either require or retain the option for a state representative to be present at abandonment.

Of 13 states reviewed in detail, we found considerable variation in required plugging procedures. While most required cement plugs, 3 allowed plugs composed of other materials. Kentucky, for example, allowed any other seal approved by the state. Ohio permitted the use of sediment, seasoned wood, properly prepared clay, or lead, in addition to cement. Pennsylvania allowed sand dumpings or mud in addition to cement.

2. REVIEW OF ABANDONMENT PROCEDURES[2]

Procedures for proper abandonment are similar for Class I-III injection wells and also are applicable to other types of wells. The ones we discuss here address wells equipped as follows:

- Casing only
- Casing and tubing
- Casing, tubing, and packer.

Further, they take into consideration four different casing configurations described in detail in Appendix B.

Abandonment of an injection well basically means the installation of one or two mechanical and cement plugs at selected depths inside the well in order to prevent vertical migration of fluids. The process consists of two phases, well preparation and plug placement. Well preparation involves cleaning the well and establishing a mud system. Plugging consists of either cementing the well top to bottom or the placement of plugs at depths specified in state regulations or approved on a case by case basis. According to Halliburton, only about 15 percent of all wells are cemented top to bottom. This figure includes most Class III wells. The remainder of this chapter discusses in detail the abandonment of Class I, II, and III wells.

[1] Approval may be in the form of a [illegible] plugging permit or a letter from the state in response to the operator's [illegible] of intent.

[2] [illegible]

(1) Class I and II Well Preparation

Two initial steps are common to all Class I and II abandonment operations. The first step is to move in a work-over rig of a size and power commensurate with the well depth and diameter. The next step is to remove any injection tubing in the well. Where there is tubing and a packer, it is possible either to remove both or to cut off the tubing above the packer after placing a ball valve in the seating nipple of the tubing.

Subsequent steps depend upon the condition of the casing. If the well casing above the cut off tubing and packer is in good condition, it is possible to complete abandonment by placing a cement plug on top of the packer, thereby eliminating the need for a mud system in static equilibrium and mechanical plug. In other cases, the next step is to clean out the hole to the bottom. Although this procedure typically is quick, it could involve removal of debris with a trash basket or fishing operation. The fishing could be simple or long and arduous. Proper cleaning of the hole is necessary to set plugs properly.

After cleaning the hole, the next step is to establish a mud system and, by circulating it, to achieve static equilibrium. Indicators of the achievement of static equilibrium are the absence of mud movement and the exclusion of those fluids and gases which would cause movement. The importance of achieving static equilibrium is to prevent any contamination or break-up of the cement which would weaken it and result in a poorly set plug. In wells under pressure, the mud can be weighted through the use of additives such as salt or a blowout preventer can be used to overcome the pressure. When a blowout preventer is used, pressure occurs on its underside but the mud, nevertheless, can be circulated to static equilibrium.

The final step in well preparation is to prepare the casing wall or wall of the open hole for cementing. The lower portion of the tubing or drill pipe that is lowered in the hole to set the plug and cement should be equipped with centralizers and rotating wall scratchers. The rotation of the scratchers cleans the bore to accomplish better bonding, allows bypassed mud to mix uniformly with the cement, helps to minimize or prevent the formation of channels in the cement, and minimizes mud contamination. This tool may be used with a scouring type chemical wash which will flush the sides of the well.

(2) Class I and II Plug Placement

The circumstances under which static equilibrium of the mud system has been achieved will affect the manner of plug placement. If the mud has been brought to static equilibrium without the use of a blowout preventer, the mechanical plug(s), on top of or through which cement is placed, are lowered very carefully through the motionless mud to the desired depths. After the bottom plug has been set, cement displaces part of the mud at the surface to form a surface plug. After proper plugging, maintenance of static equilibrium is no longer important since its principal purpose was to prevent the mud from separating and contaminating the cement used for plugging.

Where a blowout preventer has been used, the plugs are set through the preventer. The upward pressure on the underside of the blowout preventer has subsided so that the blowout preventer can be removed and a surface cement plug installed.

Several methods of plug installation are available. Of these, the Balance Method is used most commonly, but the Cement Retainer and Two-Plug Methods also are used regularly. Each of these three methods is discussed below.

1. The Balance Method

This technique involves the setting of a bridge plug in the bottom of the casing or at some other predetermined point that may be above the bottom of the casing or in the open hole below the casing. The cement slurry is pumped down the drill pipe or tubing and back up to a calculated height that will balance the cement inside and outside the pipe. The pipe is then pulled slowly out of the top of the cement. When the pipe is a considerable distance above the top of the cement, the pipe is cleaned by reverse circulation.

In this method, a small-diameter cement pipe or tubing is used in order to leave as large an annulus area as possible outside of the cement pipe. This will allow the cement pipe to be pulled from the well without causing an excessive drop in the cement or a surge of the cement plug, thereby decreasing the chance of mud contamination.

It is essential that the mud system be in static equilibrium as any fluid movement can cause a poor plug.

2. <u>The Cement Retainer Method</u>

This technique involves the installation of a cement retainer plug within a cased hole. The cement can be placed through the cement retainer plug so that the formations below the plug can be squeezed with cement. After the cementing of those formations, the cement retainer can be closed at the bottom and the cement pipe backed off from the top of the retainer. Cement then can be placed on top of the retainer by slowly withdrawing the cement pipe above it. The advantages of this system are:

- Placement of the cement below the retainer, assuring an effective plug upon closing the retainer valve
- Forcing of the cement into the formation without subjecting the old casings to high pressure
- Maintenance of good control of the cement
- Preclusion of gas percolations from the formations up past the retainer, allowing setting of the cement above the retainer without any gas diffusion
- Performance of pressure testing immediately after the retainer is set.

The method is one that is highly regarded for placing cement under pressure into a producing formation or injection zone, either through an open bore hole or through casing performations or screens.

3. <u>The Two-Plug Method</u>

The principal use of this method is in an open hole, utilizing a plug catcher into which two separate plugs are injected. It is designed to allow a bottom cementing plug to pass through the plug catcher and out of the tubing or drill pipe. Cement is then pumped out of the string at the plugging depth to fill the annulus. The top plug is introduced into the cementing string and, when it lands in the plug catcher, causes a sharp rise in the surface pressure indicating that it has closed off the plug catcher. This bottom plug is latched into place to prevent the cement from backing up into the string, but it permits reverse circulation when required. The design permits pulling the cement string up after cement placement to cut off the plug at the desired depth by reversing circulation through the plug catcher, thus allowing excess cement to be reversed up and out of the tubing. The cement string is then pulled, leaving a cement plug that should last indefinitely.

(3) <u>Abandonment of Class III Wells</u>

The relative shallowness and small diameter of Class III wells has resulted in abandonment practices which typically differ in several respects from those of Class I and II wells. Generally, Class III wells are easier and less expensive to cement top to bottom using no plug or only an inexpensive rubber plug. Thus, a work-over rig would be the only piece of equipment needed, whereas abandonment of Class I and II wells requires both work-over and cementing rigs. In addition, in many instances of Class III well abandonment, there is no need for drilling mud.

CHAPTER III

AQUIFER RESTORATION

III. AQUIFER RESTORATION

In the preamble to the proposed regulations, EPA identified aquifer restoration as one means under consideration for protecting underground sources of drinking water from contamination by Class III practices. The Agency stated that solution mining of uranium, and some other Class III practices, utilize solvents and other chemicals which can degrade the quality of groundwater in the mining area. Although the shallow aquifers in which Class III practices occur typically are not used for human consumption, contamination of hydraulically connected portions of the aquifer which are drinking water sources can occur.

EPA solicited public comment and sponsored additional investigation of aquifer restoration practices because of its concern over the technical feasibility and cost of the technology. Consequently, we undertook a review of state requirements and pilot projects.

Based on our review of current state and industry practice, we concluded that while restoration based on water use appears feasible, restoration to baseline is difficult, if not impossible. However, since aquifer restoration is a relatively new and experimental technology, the development of more efficient and economical processes is likely.

1. STATE PRACTICE

The four states which presently require aquifer restoration at in situ uranium leaching sites have different restoration criteria. As Exhibit III-1 shows, Colorado and Texas have established requirements on a project specific basis whereas New Mexico and Wyoming have based criteria on water use. In Colorado, the Department of Health used a criterion of the return of total dissolved solids (TDS) to within 10 percent of baseline and reserved the right to impose additional criteria if necessary. In Texas, the present philosophy is to restore the water quality to the average baseline value. The state requires the operator to construct at least nine wells in the production zone and at least five in nonproducing aquifers to obtain the data needed to establish the baseline value.

EXHIBIT III-1
Current State Practice
Aquifer Restoration: In Situ Uranium Leaching Sites

STATE	RESPONSIBLE AGENCY	PRINCIPAL AUTHORITY	RESTORATION CRITERIA	RESTORATION PROJECTS
Colorado	Department of Health (Water Quality Div.)	Water Quality Control Act	. No overall criteria or guidelines . For pilot project, return of TDS to within 10% of baseline	Wyoming Mineral Corp. pilot project at Grover
New Mexico	. Department of Health (Environmental Improvement Division) . Water Quality Control Commission . U.S. Geological Survey	Water Quality Act	. No restoration required if TDS baseline exceeds 10,000 mg/l . Where baseline is 10,000 mg/l or less TDS: -Restoration to baseline if baseline exceeds water quality standard -Restoration to standard if baseline is less than or equal to standard	Mobile Oil Crown Point project in McKinley County
Texas	. Department of Water Resources . Department of Health	Water Quality Act	. Project specific criteria but philosophy is to require restoration to average baseline	Several pilot scale projects; no full-scale ones
Wyoming	. U.S. Nuclear Regulatory Commission . Wyoming Department of Natural Resources	Environmental Quality Act	. Criteria based on water use, usually to livestock watering or irrigation standards	Pilot scale projects at pilot and full-scale leaching sites

Both New Mexico and Wyoming have different approaches to restoration based on water use. Regulations promulgated by the New Mexico Water Quality Control Commission state that water with a baseline of a TDS concentration in excess of 10,000 mg/l is unusable for drinking water or agriculture and does not require restoration. However, for water containing less than 10,000 mg/l TDS, the Commission has set water quality standards for three categories of usage. When the baseline value exceeds the appropriate water quality standard, restoration is to baseline; where it is equal to or less than the standard, restoration must achieve the standard.[1] In the one existing case, a simple numerical average of all water samples taken from the ore-bearing sandstone represented the baseline value. Wyoming, by contrast, has not yet developed groundwater standards. The Wyoming concept is to require restoration to a level that will permit the water use that existed prior to leaching. Because water quality is often poor in the ore-body portion of ore-bearing strata, restoration requirements usually are based on livestock watering criteria or irrigation criteria. A specific provision of the Environmental Quality Act is the requirement for a bond to allow accomplishment of restoration by the State, should the operator fail to do so.

While the extent of restoration activity in each state has varied, all projects have been pilot scale. In Colorado, the Wyoming Mineral Corporation has completed restoration at its pilot scale uranium leaching site near Grover. New Mexico also is the site of one pilot scale leaching operation, Mobil Oil's Crown Point Project in McKinley County, which started up the week of November 5, 1979. Restoration at that site is not likely to begin before late 1980. By contrast, Wyoming has had several pilot scale leaching projects, and presently has two full-scale operations subject to both Federal and state regulation.[2]

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1 Since the existing project is on Indian land, the U.S. Geological Survey (USGS) also has set restoration requirements. State officials state that the state criteria are more stringent and will prevail.

2 The NRC issues source licenses because Wyoming is a non-agreement state. In addition, the land and water quality divisions of the Department of Natural Resources issue permits required by the Environmental Quality Act.

Since Wyoming requires evidence of the ability to restore, based on pilot scale experience, prior to issuance of permits for full-scale operations, it can be concluded that the state has been satisfied with the results that have been obtained in the restoration of pilot areas for at least the two current full-scale operations. According to Gary Beach, of the Wyoming DEQ, some areas of the Wyoming Minerals Irigaray full-scale leaching site have probably gone to the restoration stage, since that project has now been in operation for over one year.

2. EVALUATION OF AQUIFER RESTORATION METHODS

Restoration means the reduction of the concentrations of dissolved minerals within the leaching field and adjoining portions of the aquifer to levels acceptable to and set by regulatory agencies. Techniques which have been proposed, or tried on a pilot scale, include:

- Pumping of selected leach field wells
- Pumping in combination with injection
- Natural restoration.

On the basis of the results of pilot projects together with a consideration of geological and geochemical principals, we have concluded that restoration of all parameters to baseline is quite difficult, if not impossible; however, restoration to water quality standards based on water use is feasible. In the remainder of this section, we summarize information on aquifer restoration techniques and cases previously prepared by Geraghty and Miller for the Nuclear Regulatory Commission.[1]

(1) Pumping of Selected Leach Field Wells

The initial concept of leach field restoration, as developed in Texas, involves only the pumping of

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1 Ground-Water Elements of In Situ Leach Mining of Uranium, prepared by Geraghty and Miller for the Nuclear Regulatory Commission (NUREG/CR-0311), August 1978. Chapter 6 of the report, "Methods of Aquifer Restoration," is reprinted in Appendix C of this report on proper well abandonment.

selected wells after cessation of lixiviant injection. The purpose of the pumping is to draw uncontaminated groundwater from outside the leaching field in order to displace the injected lixiviant and the constituents mobilized by it. In theory, this groundwater should displace the lixiviant completely, producing a water quality that is the same as the average baseline quality.

Data from the Exxon Company's Highland Uranium Mine show that although pumping improved the water quality resulting from the solution mining, it did not restore all parameters to baseline. Uranium concentrations showed an irregular, but clear tendency, toward reduction but remained significantly above the average baseline value. Carbonate and bicarbonate levels also declined significantly, with the bicarbonate level reaching baseline. Radium-226 was originally high and declined somewhat. Also, selenium concentrations decreased significantly, whereas arsenic levels did not.

There are three principal reasons for the only partial success of pumping. First, the sandstone bodies of the type in which uranium leaching is practiced are naturally inhomogeneous and commonly include preferred paths of fluid flow. Thus, during restoration, while the inflowing groundwater readily will sweep contaminants from these preferred paths, it will bypass other contaminated areas. Removal of the bypassed water will occur slowly later in the resotration. Second, some ions which adsorb to minerals such as clay begin to desorb during restoration. Since the desorption process is very slow, the ions remain in the water for a long time. Finally, the leaching process disturbs the existing chemical equilibrium, and pumping may not be able to reestablish it.

(2) <u>Pumping In Combination With Injection</u>

A second restoration method is to supplement pumping with the simultaneous injection of various types of water into other wells. The pumping would draw out the injected lixiviant and mobilized ions, while the injection would drive the contaminated water toward the pumping wells.

The variations on this method either have been only partially successful or have not been tried yet.

Injection of natural groundwater appears to have no advantages since pumping alone draws in natural groundwater at less cost and technical difficulty. In contrast, Wyoming Mineral Corporation achieved significant concentration reductions at its Irigaray, Wyoming site with the injection of treated leach field water. Treatment and reinjection of the pumped water also has the advantage of reducing the amount of contaminated water that must be disposed. One disadvantage, however, is that injection of water would introduce oxygen which would cause continued oxidation and mobilization of uranium and other methods, unless some form of deaeration precedes injection. A third variation, the injection of water containing chemicals such as reducing agents to remove uranium and trace metals from solution, is not known to have had a field application.

(3) Natural Restoration

The concept of natural restoration is as yet untried and appears to have at least three difficulties. It is based on the belief that reprecipitation, ion exchange, adsorption, or reduction will result in the removal of most of the objectionable contaminants resulting from the leaching process. In other words, it relies upon the restorative capacity of the ore-bearing stratum and the uncontaminated groundwater. However, there is difficulty in predicting the time and distance required for effective contaminant removal, the degree of removal achievable, and the ultimate fate of some ions and elements such as chloride and ammonia.

CHAPTER IV

COSTS OF ABANDONMENT

IV. COSTS OF ABANDONMENT

The proposed regulations contain no specific technical requirements for abandonment, other than the one described in Chapter III for achieving static equilibrium. Analyses prepared in support of those proposals did not address abandonment costs, and commenters on the regulations did not object to the costs of proper abandonment procedures.

Nevertheless, in order to complete the record, EPA requested a detailed definition of both unit and category costs of proper abandonment. In conducting this research for EPA, we had two objectives:

- Develop costs of abandoning Class I-IV wells

- Determine whether the proposed regulations impose incremental costs to operators for abandonment of Class I, II, and III wells.[1]

Our approach first was to define the principal abandonment steps and their cost based on literature review, professional experience, and interviews with well service companies. Next, we reviewed current state regulations and interviewed state officials to ascertain the additional requirements which Federal rulemaking would impose.

Based on our data collection and analysis, we arrived at the following principal findings. First, incremental costs appear to be small since of 37 states surveyed, at least half have extensive abandonment regulations covering 82.8 percent of the reported Class I wells and 97.4 percent of reported Class II wells. State officials reported that typically the state either had or was developing abandonment regulations for Classes I and III patterned after Class II requirements. Incremental costs, therefore, are likely to occur only in those states which do not have an extensive program or in which the requirements differ significantly from those which EPA will find acceptable for primacy. In

[1] We [illegible] Class IV wells [illegible]

the former situation, a significant number of operators already follow good engineering practice when abandoning. The latter situation may occur in states such as Pennsylvania, Ohio, and Kentucky where, in contrast to the proposed EPA rules, plugging materials such as sediment, lead, seasoned wood, and clay are permissible plugging substitutes for cement. Second, abandonment costs for Classes I, II, and III appear small relative to other costs such as drilling, construction, and operation. It is important to note, however, that the relatively small experience with Class III operations makes unit cost estimation difficult. Finally, we had difficulty estimating Class IV unit costs and did not develop category costs since the lack of data on types and numbers of Class IV operations precluded estimating the costs of alternative treatment methods.

1. UNIT COSTS OF ABANDONMENT

The cost for injection well abandonment varies according to the depth and diameter of the well, the condition of the casing and other materials in the well, and on any procedures that may have to be taken to clean out or otherwise prepare the well prior to plug installation. For Class I, II, and III injection wells, we have been able to make some general observations about well depth and diameter,[1] as shown in Exhibit IV-1.

In developing the unit costs, we used certain criteria in order to standardize the estimates. First, we used the most common well diameter and depth range for each type of well. Second, the costs we developed are those for a normal job. Therefore, there are not costs included for additional rig time necessitated by weather, trouble in the well, mechanical problems, or the need for perforating and squeezing cement opposite aquifers in wells that were not cemented top to bottom on the outside of the casing. It is not possible to predict any of these situations, and their cost can be considerable.

The remainder of this section summarizes the unit costs and provides detailed analysis of these costs. Exhibits IV-2 through IV-5 present the unit costs for the different classes of wells. Exhibit IV-6 summarizes the unit costs

1 Figures for these classes reflect current practice. Numbers for Class IV are only estimates since data about these operations are unavailable.

EXHIBIT IV-1
Typical Depth and Diameter Characteristics
of Injection Wells

Class	Type	Depth Range	Common Diameter
I	Industrial Municipal	1,000 - 9,000 1,000 - 4,000	9 5/8 inches 16 inches
II	Storage Production	1,000 - 3,000 3,000 - 15,000	5 1/2 inches 5 1/2 inches
III	Solution Mining In-Situ	100 - 1,000 100 - 1,000	4 1/2 inches 4 1/2 inches
IV	All*	100 - 1,000	4 1/2 inches

*Since the types and sizes of Class IV operations are unknown, we developed these estimates for unit cost purposes only.

EXHIBIT IV-2
Unit Costs of Plugging Class I Wells

Well Depth (feet)	Industrial Injection Wells (Common Diameter 9 5/8 inch)				Municipal Injection Wells (Common Diameter 16 inch)			
	Well Prepa-ration Cost ($)	Cementing Cost ($)	Rig Cost ($)	Total Cost ($)	Well Prepa-ration Cost ($)	Cementing Cost ($)	Rig Cost ($)	Total Cost ($)
1,000	$ 1,900	$ 4,500	$ 2,700	$ 9,100	$ 6,000	$14,000	$ 2,700	$22,700
2,000	3,800	4,800	2,700	11,300	12,000	14,000	2,700	28,700
3,000	5,700	4,800	3,600	14,100	18,000	14,000	3,600	35,600
4,000	7,400	4,900	3,600	15,900	24,000	14,000	3,600	41,600
5,000	9,200	7,300	3,600	20,100				
9,000	17,000	8,700	5,400	31,100				

EXHIBIT IV-3

Unit Costs of Plugging Class II Wells

Well Depth (feet)	Oil and Gas Storage Wells (Common Diameter 5-1/2 inch)				Wells Associated with Oil and Gas Production (Common Diameter 5-1/2 inch)			
	Well Prepa- ration Cost ($)	Cementing Cost ($)	Rig Cost ($)	Total Cost ($)	Well Prepa- ration Cost ($)	Cementing Cost ($)	Rig Cost ($)	Total Cost ($)
1,[illegible]	$ 720	$ 2,800	$ 2,700	$ 6,220				
[illegible]	1,400	2,900	2,700	7,000				
[illegible]	2,100	2,900	3,600	8,600	$ 2,100	$ 2,900	$ 3,600	$ 8,600
4,[illegible]					2,900	3,000	3,600	9,500
[illegible]					3,600	4,100	3,600	11,300
[illegible]					6,300	5,300	5,400	17,000
1[illegible],[illegible]					10,800	9,900	9,800	30,500

EXHIBIT IV-4

Unit Costs of Plugging Class III Wells

Well Depth (feet)	Solution Mining Wells (Common Diameter 4-1/2 inch)				In-Situ Wells (Common Diameter 4-1/2 inch)			
	Well Preparation Cost($)	Cementing Cost($)	Rig Cost($)	Total Cost($)	Well Preparation Cost($)	Cementing Cost($)	Rig Cost($)	Total Cost($)
100	$ 100	$ 400	$ 1,000	$ 1,500	$ 100	$ 400	$ 1,000	$ 1,500
500	500	700	1,000	2,200	500	700	1,000	2,200
1,000	800	1,300	1,250	3,350	800	1,300	1,250	3,350

EXHIBIT IV-5

Unit Costs of Plugging Class IV Wells

Well Depth (Feet)	Class IV Wells (Common Diameter and Common Depths Unknown; 4-1/2 Inch Diamter Assumed for Costing Purposes)			
	Well Preparation Cost ($)	Cementing Cost ($)	Rig Cost ($)	Total Cost ($)
100	$100	$400	$1,000	$1,500
500	500	700	1,000	2,250
1,000	800	1,300	1,250	3,350

for the different classes of wells. Exhibit IV-6 summarizes the unit costs for abandoning those Class I and II wells which have the most commonly occurring depth and diameter. Insufficient data is available to define the most common methods of construction of Class III and IV wells. However, the types of construction available are similar to those used in Class I and II, and, since Class III wells are relatively shallow, their abandonment costs are significantly lower.

(1) Well Preparation

The principal cost item of well preparation, other than the work-over rig which is treated separately, is that of establishing the mud system. The normal range in mud weight is from 10 lb/gallon to 20 lb/gallon, although some circumstances require heavier mud. The cost of the mud ranges from $5.00 per barrel for the 10 lb/gallon mud to $50.00 per barrel for the 20 lb/gallon mud. For the purposes of this study, we used 13 lb/gallon mud at a cost of $24.00 per barrel, and we used theoretical quantities.[1]

(2) Cementing

This item includes the costs of one mechanical plug, placement, cement, and transporting the cement and mobile equipment to the job site. Exhibit IV-7 shows the costs of the cement for cementing wells of various depths. These costs are average ones for Type 2 or Class H cement and include a per sack service and transportation charges for delivery from a base 200 miles away. The transportation charge is $0.54 per ton/mile everywhere in the United States except the Rocky Mountain area where it is $0.59 per ton/mile. The cost of the Type 2 or Class H cement, itself, without lost circulation material ranges from $3.38 to $6.15 per cubic foot (equivalent to one sack). Other cement types may cost as much as $25.00 per sack. Exhibit IV-8 lists costs for cement placement. If wells are cemented top to bottom, cementing costs for Class I roughly are a factor of 5, and for Class II a multiplier of 2.5. However, as noted in Chapter III, only about 15 percent of all Class I and II wells, according to Halliburton, are filled completely with cement.

Transportation of mobile equipment incorporates a mileage charge for each such piece of equipment sent

1 In some formations, sink-holes or crevices can result in the use of quantities significantly in excess of the theoretical quantity.

EXHIBIT IV-6
Summary of Unit Costs of Abandonment for
The Most Common Depths of Wells in
Classes I and II

Well Class	Well Type	Depth (feet)	Diameter (inches)	Well Prepar-ation Cost	Cement-ing Cost ($)	Rig Cost ($)	Total Cost ($)
I	Industrial	4000	9-5/8	$7,400	$4,900	$3,600	$15,900
I	Municipal	4000	16	24,000	14,000	3,600	41,600
II	Oil and Gas Storage Wells	2000	5-1/2	1,400	2,900	2,700	7,000
II	Wells Associated With Oil And Gas Production	5000	5-1/2	3,600	4,100	3,600	11,300

EXHIBIT IV-7
Summary of Costs of Cement*

Well Depth (feet)	Cement Used (linear ft.)	Cost Per Cubic Foot
To 4,000	400	$11.87
4,000-9,000	800	12.51
9,000 - 15,000	1,200	13.60

* Includes cement, service and transport charge

EXHIBIT IV-8
Costs of Cement Placement

Depth	Cost*
0-300	$ 325.00
300-1,500	325.00
1,500-3,000	757.00
3,000-5,000	757.00
5,000-7,000	891.00
7,000-9,000	1,101.00
9,000-11,000	1,491.00
11,000-13,000	2,231.00
13,000-18,000	3,551.00
18,000-25,000 or below	7,126.00
Each additional 8 hours or fraction on location, per unit, for each depth interval is $[illegible].	

* For 8 hours or fraction, for each [illegible] each increment, minimal number of additional feet, the [illegible] that of the next increment; for example [illegible] [illegible]

to the job. Normally, a cement mixing and pumping unit (cement rig) is the only mobile unit sent for this purpose. The mileage charge to and from the job is $1.55 per mile in all of the United States, except in the Rocky Mountain area, where it is $1.60 per mile.

Mechanical plugs may be bridge plugs, packers, or cement retainer plugs. These plugs are permanently installed in the well during the abandonment procedure. They range in size from a 2-inch rubber plug to a 16-inch plug, and cost from $250 to approximately $6,000. Where the Two-Plug Method is used, the plug catcher is retrievable and is rented out at a cost of $150, which would reduce the cost. For each of the Class I and Class II wellls, the cost of one permanent plug has been included in the cementing cost.

(3) Rig Cost

This item includes all costs associated with the work-over rig and crew used for abandoning all classes of wells. For Class III, the work-over rig is the only piece of equipment needed, whereas Class I and II abandonment also requires a cementing rig. If abandonment of a Class III operation were to require a service company, it would increase the unit costs in Exhibit IV-4 as follows:

- 100 foot well - $600
- 500 foot well - $700
- 1000 foot well - $800.

The estimated Class III costs assume a mud weight of 9 lb/gallon and cementing top to bottom with no plug or an inexpensive rubber plug. The rig costs shown in Exhibits IV-2 through IV-6 represent hourly rig charges multiplied by typical rig time on standard jobs as shown in Exhibit IV-9.

2. CATEGORY COSTS AND INCREMENTAL COSTS

Time limitations prevented us from being able to calculate both category costs and incremental costs. With respect to category costs, although data was available on the number of wells within categories I, II, and III, no data was available either on the projected rate of abandonment nor the distribution by depth and diameter. Collection of this data, if possible at all, would be extremely time-consuming and beyond the time allotted for this assignment. Similarly,

EXHIBIT IV-9

Summary of Rig Costs

Class I, II			
Depth	Hours	Cost/Hr	Total
1,000	30	$90	$2,700
3,000	40	$90	$3,600
5,000	40	$90	$3,600
9,000	60	$90	$5,400
15,000	70	$140	$9,800

For Class III and IV, the hourly charge typically is about $50.00 and the rig time ranges from 20-25 hours.

time constraints precluded a sufficiently comprehensive examination of current state regulation to form the basis of even an estimate of incremental cost. However, as noted in the beginning of this chapter, we have identified a substantial number of states which have abandonment regulations covering well over half of the Class I and II wells. With additional investigation, it is likely we would find other states also having regulations. Consequently, it appears that the incremental costs will be fairly small, particularly when viewed in context of the larger costs associated with well drilling, construction, and operation. In a few instances, mentioned above, states allow plugging materials other than cement, in contrast to EPA's proposals. Operators in those states would have the added expense of using only cement plugs.

CHAPTER V

ALTERNATIVES FOR DEMONSTRATING FINANCIAL RESPONSIBILITY

V. ALTERNATIVES FOR DEMONSTRATING FINANCIAL RESPONSIBILITY

The proposed regulations require operators to demonstrate, through a performance bond or other means, the availability of adequate resources to finance proper plugging and abondonment. EPA's principal objectives in setting this requirement are to reduce the incidence of improper well abandonment and assure that if it occurs funds are available to the state to carry out plugging.

EPA is concerned, however, about the objections which industry has voiced. Approximately 20 commenters, primarily gas and oil operators, stated that the cost of obtaining individual well bonds was prohibitive and tied up capital which could be used for exploration and development. Further, they stated that current state bonding requirements were sufficient, precluding the need for a Federal requirement, and that the state already had sufficient means for reaching operator assets. Finally, some commenters asserted that submittal of financial statements was sufficient for companies with substantial assets and that, in fact, demonstration of financial responsibility was unnecessary.

In order to assist EPA in responding to industry's comments, we identified and evaluated alternatives for demonstrating financial responsibility. Our approach included a review of current state regulations and similar requirements under the Resource Conservation and Recovery Act supplemented by telephone interviews with well operators, state officials, and surety company representatives. The remainder of this chapter contains our evaluation of the alternatives and discussion of our principal findings.

1. ALTERNATIVES FOR DEMONSTRATING FINANCIAL RESPONSIBILITY

Well operators have four basic options for demonstrating financial responsibility:

- Financial statements
- Performance bonds
- Escrow accounts
- Trust funds.

Some of these, such as bonds and trust funds, have several variations. Each operates uniquely in terms of the financial and compliance obligations of the operator and the role of the regulatory agency.

(1) Financial Statement

The simplest alternative an operator has for demonstrating financial responsibility is to submit a financial statement prepared by a certified public accountant. This statement indicates the operator's net liquid assets and, therefore, financial stability and reliability. Federal regulations require public corporations to prepare such statements, and many private corporations also routinely prepare them for tax, credit, or other purposes. A regulatory agency's acceptance of a financial statement reflects the agency's perception of a relationship between an operator's financial assets and its overall reliability in meeting regulatory obligations.

(2) Escrow Accounts

A second, more complex, alternative is the establishment of an escrow account, an account in which the well operator deposits funds for abandonment prior to the anticipated abandonment date. The operator may use the funds in an escrow account only to meet abandonment costs, and an account administrator verifies both proper deposits and disbursements. Depending on how state regulations are written, the operator may have to deposit either the entire anticipated abandonment cost or a sum which by the abandonment date will yield anticipated cost. If the inflation rate exceeds the rate of return on the account, the account may not contain sufficient funds at the time of abandonment and plugging.

(3) Trust Fund

A third alternative is for the operator to deposit funds in trust for the specific purpose of meeting the plugging and abandonment costs. The trust agreement, drawn by an attorney, specifies the conditions of the trust including its duration and trustee. The trustee is responsible for administering the trust, which may include investment management and planning in addition to assuring appropriate use of the funds.

Two distinct types of trusts are individual or industry trusts. The former is a trust fund which a single operator establishes specifically to have funds available for proper abandonment of his well(s). Typically, the operator must set aside a sum equal to the anticipated costs of plugging and abandonment. If, as a result of the trustee's investments, the amount of the fund exceeds the sum required for abandonment, the remainder reverts to the operator. Under an industry-wide trust fund, individual operators contribute annual assessments which usually depend both on the number of contributers and the rate of compliance. In contrast to the individual trust, the funds of an industry trust are available only in cases of noncompliance.

(4) Performance Bonds

A performance bond guarantees the operator's performance of a particular obligation over a specific period of time. According to industry, operators cannot obtain long-term bonds. Therefore, the bonds typically run for one year and are renewable annually. While surety companies have the option to cancel the bond or change the premium, they have not done so as a rule. The surety company usually is obliged to notify the state a set number of days prior to the bond's expiration whether the bond has been renewed or cancelled.

An operator typically submits a bond secured by a licensed surety company, although in some cases operators may deposit cash, certificates of deposit, or governmental revenue or general obligation bonds with the state treasurer. In some states, the surety company, in cases of nonperformance, must provide the state with either the amount of the bond or closure costs whereas in other states the surety company has the option of either taking responsibility for abandonment or providing the state with the funds. It then attempts to recover the forfeited amount from the operator.

The surety company can issue several different categories of bonds. For example, the bond may vary according to whether it covers a single well (individual well bonds) or several operations (blanket bond). It also may vary according to the applicant's financial status. In theory, all performance bonds are either surety or security bonds. The surety companies issue surety bonds to financially sound operators and security bonds to those who are not. In the former, the operator pays only an annual premium whereas in the latter he not only pays a premium but also posts collateral.

Collateral must consist of treasury bills, cash, certificates of deposit, government secured revenue or general obligation bonds, or an irrevocable letter of credit. Surety companies file premium rates with state insurance commissions. Although there is a basic rate, companies can file a discount rate which they then apply to financially strong applicants; they cannot impose a surcharge on financially weak companies.

2. STATE REQUIREMENTS

One objective was to evaluate commenters' objections by determining the extent to which the proposed Federal regulaations would impose new obligations on operators. Therefore, we attempted to identify current state requirements for demonstrating financial responsibility for proper plugging. Within the time alloted, however, we were unable to accomplish as comprehensive a review as might be desirable. While we identified the financial responsiblity requirements for Class II operations in all 37 states having such operations, we obtained only limited information on Class I and III wells.

Based on this limited analysis, we have concluded that in some states the Federal regulations may impose a potentially significant new obligation. Exhibit V-1 summarizes our findings. For example, since Texas and Kansas are not among the 84 percent (31) of states requiring financial responsibility demonstration for Class II, about 50 percent of the wells are not subject to such requirements. Of the states having the requirement, all provide for performance bonds. In Oklahoma, only blanket bonds are permissible, whereas Indiana, Maryland, North Carolina, and Oregon allow only individual bonds. The remainder permit both types. The amounts of the required individual bonds range from a low of $750 in Ohio to a high of $100,000, while the blanket bonds range from $3,500 (Ohio) to $200,000 (Florida). West Virginia allows escrow accounts as a substitution for a perforamnce bond, whereas Ohio and Oklahoma will accept financial statements.

With respect to Class I and III operations, our limited data suggests that there are financial responsibility requirements, and that operators most commonly comply with the requirements by obtaining a performance bond. A few states (Kansas, Oregon, Washington, and Wisconsin) apparently allow the use of escrow accounts or trust funds. In general, however, these mechanisms apply to liability coverage rather than to performance of specified obligations. Finally, states tend to have requirements for Class III wells similar to those for Class II operations.

EXHIBIT V-1

State Financial Responsibility Requirements
for Class II Wells

[illegible]	[illegible]	FINANCIAL RESPONSIBILITY REQUIREMENT	CONDITION OF THE REQUIREMENT	INDIVIDUAL WELL BOND	BLANKET BOND	ESCROW ACCOUNT	TRUST FUND	FINANCIAL STATEMENT
[illegible]	•	•	Plugging	$ 5,000-$ 50,000	$100,000			
[illegible]		•	Operations	$50,000-$[illegible]	$100,000			
[illegible]	•	•	Compliance	$ 5,000	$ 25,000			
[illegible]	•							
[illegible]	•	•	Operations	$10,000-$ 25,000	$100,000			
[illegible]	•	•	Plugging	$ 5,000	$ 30,000			
[illegible]	•	•	Plugging	$10,000-$ 50,000	$200,000			
[illegible]	•	•	Plugging	Flexible	Flexible			
[illegible]	•	•	Compliance	$ 5,000	$ 10,000			
[illegible]	•	•	Plugging	$ 1,000	$ 10,000			
[illegible]	•	•	Plugging	$ 1,000				
[illegible]	•							
[illegible]	•	•	Plugging	$ 1,000	$ 5,000			
[illegible]	•	•	Plugging					
[illegible]	•	•	Operations	$ 2,500				
[illegible]	•	•	Plugging	$ 5,000	$ 50,000			
[illegible]	•							
[illegible]	•	•	Operations	$ 1,000-$ 3,000	$ 10,000-$30,000			
[illegible]	•	•	Plugging	$ 5,000	$ 10,000			
[illegible]	•	•	Compliance	$ 2,500	$ 10,000			
[illegible]		•	Plugging	$ 2,500	$ 10,000			
[illegible]	•	•	Plugging	$ 5,000-$ 12,500	$ 50,000			
[illegible]	•	•	Plugging	$ 1,000-$ 2,000	$ 4,000-$ 8,000			
[illegible]	•	•	Plugging	$ 5,000				
[illegible]	•	•	Compliance	$ 5,000				
[illegible]	•	•	Plugging	$ 750-$ 1,500	$ 3,500-$ 5,000			•
[illegible]	•	•	Plugging		$ 10,000			•
[illegible]	•	•	Compliance	$10,000				
[illegible]	•							
[illegible]	•	•	Plugging	$ 5,000	$ 20,000			
[illegible]	•	•	Plugging	$ 2,000	$ 10,000			
[illegible]	•		Plugging	$ 5,000	$ 10,000			
[illegible]	•	•	Plugging	$10,000	$ 50,000			
[illegible]	•	•	Compliance	$ 2,500-$ 10,000	To Be Determined			
[illegible]	•	•	Plugging	$ 5,000-$ 10,000	$ 10,000-$25,000			
[illegible]	•	•	Operations	$ 2,500	$ 15,000	•		
[illegible]	•	•	Plugging	$ 5,000	$ 25,000			

[illegible] requires a permit or some other type of state approval.
[illegible] these states in its review of regulations in all producing states, although
[illegible]
[illegible] requirement.

3. EVALUATION OF THE ALTERNATIVES

We utilized three criteria for evaluating the four financial responsiblity alternatives:

- Cost to the operator
- Ease of implementation
- Effectiveness in promoting proper abandonment.

The first criteria takes into consideration any collateral, annual fees, and the opportunity cost of capital. Exhibit V-2 displays the comparative costs of the alternatives.[1] Ease of implementation examines current practice and the impact on the management resources of the regulatory agency. Finally, the effectiveness criteria includes the extent to which each alternative promotes operator compliance and makes available sufficient funds in case of noncompliance.

In general, we found performance bonds to be the most effective alternative. The effectiveness of other alternatives apparently varies with the way states have worded their regulations and with the vigilance of enforcement. Exhibit V-3 summarizes our evaluation.

(1) Financial Statements

This mechanism is responsive to operators' concerns with cost but is neither easy to implement nor particularly effective. It is the least costly alternative because most companies routinely prepare financial statements as part of their business operations and because the operator does not forgo the use of capital. However, the regulatory agency may not have either sufficient manpower or technical capability to carry out the evaluations of the statements or the monitoring of companies' financial status. In addition, a Federal regulation that state programs include a requirement for submittal of a financial statement would require significant legislation and rulemaking since this alternative is in infrequent use. Finally, the mechanism is not a particularly effective one. Since the operator does not set aside any capital which might be forfeited, there is no explicit incentive to comply. Additionally, in cases of noncompliance, no funds are available to the state for plugging, unless the state has a plugging fund.

1 Appendix D describes our methodology for calculating these costs.

EXHIBIT V-2
Comparative Costs of Financial Responsibility Alternatives

ALTERNATIVE	ONE YEAR BEFORE CLOSURE	FIVE YEARS BEFORE CLOSURE	TEN YEARS BEFORE CLOSURE	TWENTY YEARS BEFORE CLOSURE
[illegible] Statement	No special cost associated with abandonment since businesses typically prepare financial statements. Provides baseline for comparison.			
[illegible] Bond				
Surety Bond[1]				
[illegible]	1%-1.5%	5.5%- 8.3%	43.7%-51.7%	33.1%-49.6%
[illegible]	1%-1.5%	20.1%-23.4%	63.8%-74.0%	43.3%-65.0%
[illegible] Bond[2]				
[illegible]	4.0%-4.5%	21.0%-23.7%	72.3%- 79.2%	104.6%-118.7%
[illegible]	5.4%-5.9%	29.4%-32.2%	110.7%-118.7%	161.2%-177.8%
[illegible] Account[3]				
[illegible]	[illegible]	12.9%	51.4%	62.2%
[illegible]	3.9%	21.1%	86.8%	111.6%
[illegible]	[illegible]	54.1%	163.0%	229.2%
[illegible]				
[illegible] Trust [illegible] Trust	Costs will depend on the type of trust, attorney fees, years before closure, disbursements (industry trust only) and whether the trustee manages the funds or is merely a custodian of the funds.			

[illegible] is in present value terms, identifying for four different periods prior to [illegible] the amount of funds which will yield the necessary abandonment costs. " " [illegible] the operator's internal rate of return.

[1] [illegible] an annual premium/service charge of 1%-1.5%.

[2] Assumes an annual premium/service charge for the bond of 1%-1.5%, an annual service charge of 1.[illegible] for an irrevocable letter of credit; and a real annual interest of 2% on the letter of credit. The cost will vary if certificates of deposit or government securities [illegible] serve as collateral.

[3] Assumes an annual service charge of 1% and an annual real interest rate of 2%.

EXHIBIT V-3
Evaluation of Alternatives

ALTERNATIVE	COMPARATIVE COST TO THE OPERATOR	EASE OF REGULATORY IMPLEMENTATION	EFFECTIVENESS IN PROMOTING PROPER ABANDONMENT
Financial Statements	Least cost because operator incurs no additional costs and has access to the funds	Regulatory agency has to evaluate each operator on a case by case basis and monitor the operator's financial status frequently	Does not promote compliance or assure availability of funds; operator does not set aside funds or forfeit anything upon noncompliance
Performance Bonds	Minimal cost for surety bond because operator does not have to post collateral and has access to the funds; higher costs for security bond because operator has to post collateral and does not have access to the funds	Surety company evaluates each operator's financial status and issues the appropriate bond; regulatory agency only has to verify the value of the bond	Promote compliance and assures availability of funds; operator forfeits the bond in case of noncompliance and surety company provides funds for closure costs
Escrow Accounts	Higher cost because operator has to deposit funds prior to closure and does not have access to the funds until closure	Regulatory agency has to verify the deposit of the funds and may have to administer the account (that is, disburse funds and monitor appropriate use of funds)	Does not promote compliance, but assures availability of funds; operator deposits the funds prior to closure
Trust Funds	Higher cost because operator has to deposit funds prior to closure, pay trustee to manage the fund, and not have access to the funds until after proper abandonment; industry trust may be lower cost than individual trust if high probability of compliance	Trustee manages the fund and assures the availability of funds; regulatory agency has to verify the deposit of the funds and may have to evaluate probability of noncompliance and annual assessments for industry trust	Both promote compliance by preventing forfeiture (individual) or reducing annual payments (industry). Industry trust fund may be insufficient if fund is small and noncompliance high

(2) Performance Bonds

Of the four alternatives evaluated, performance bonds are most consistent with EPA's objective of promoting proper abandonment. Apparently, in practice operators have difficulty in obtaining bonds without collateral; therefore, the possibility of forfeiture provides a disincentive for noncompliance.[1] Furthermore, when noncompliance does occur, funds are available for either the surety company or the state to plug the well.

From the regulatory agency's perspective, performance bonds are considerably easier to implement than other financial responsibility alternatives. Most states which have well operations already require performance bonds. In addition, since the surety company conducts the requisite financial analysis, issues a bond appropriate to the operator's financial status and duration of obligation, and notifies the agency of any expiration, cancellation, or renewal of the bond, this mechanism poses no significant technical or manpower demand on the agency.

There is some evidence to suggest, however, that operators do not universally obtain these bonds with ease. Despite the theoretical opportunity for a financially sound operator to obtain a surety bond, apparently most performance bonds, in fact, require collateral. The surety company retains this collateral either in its local or home office safe until the performance conditions are met. According to operator and surety company representatives, in some cases operators experience difficulty in securing bonds even with collateral. In particular, for security bonds ranging from $1,000 to $5,000, the premiums are relatively small and the handling of collateral or costs of claims do not justify issuing the bond.

The actual cost to the operator of submitting a bond in fulfillment of the financial responsibility requirement will vary according to the type and amount of the bond. As Exhibit V-2 indicates, security bonds, because they require collateral and therefore involve significant opportunity costs, are more costly than surety bonds. In addition, for operators with multiple operations, securing of individual well bonds would be of greater cost than blanket bonds. In general, however, this alternative is more costly than financial tests but less costly than escrow accounts or trust funds.

[1] [illegible]

(3) Escrow Accounts

This third alternative is not a particularly attractive one. It is quite costly for the operator to forego the use of the capital in the escrow account over the extended time period between permit application and well abandonment. As shown in Exhibit V-2, the cost of creating an escrow account will include an annual administration cost of 1 percent of the account value, as well as the real opportunity cost of capital. This latter cost assumes an annual real interest rate of 2 percent on the account. Implementation of this mechanism also can be disadvantageous to the regulatory agency. It requires the agency to conduct some monitoring of the account and perhaps to administer the account. In addition, the agency will have to determine the appropriate size of the account and verify deposit of the funds. Finally, the escrow account is only partially effective in that it assures the availability of funds in cases of noncompliance.

(4) Trust Funds

Trust funds, like escrow accounts, are fairly unattractive. First, they tend to be costly, although the exact cost will vary according to the terms of the trust. Individual trusts which are of lengthy duration are significantly costly because the operator incurs not only attorney and trustee fees but also substantial opportunity costs of foregoing capital. The operator may be able to reduce the overall cost of the trust by paying a higher fee for the trustee fee to actually manage the funds and obtain high investment yields offsetting the fees. The costs of the industry trust may be lower if high compliance results in relatively nominal annual assessments. However, these annual assessments are incremental to the actual abandonment cost whereas the funds of the individual trust pay for closure.

The ease of implementation will depend upon the nature of the trust. For example, industry trusts may have selective memberships to ensure that the financially sound operators do not subsidize less reliable ones. Thus some operators may be unable to participate in a trust. In addition, the regulatory agency will have to monitor deposits to individual trusts and payment of annual assessments to industry trusts in order to determine whether a permit applicant who is participating in a trust sufficiently has met the financial responsibility requirement.

Finally, the trust fund is only a partially effective means for promoting proper abandonment. Typically, the individual trust agreement specifies that the operator will not have access to the funds until after proper abandonment and in case of noncompliance makes the funds payable to the state. Thus, this mechanism provides little incentive for compliance but assures the availability of funds. By contrast, the industry trust promotes compliance because high compliance generally results in low annual assessments. However, the funds may be insufficient in a given year to cover all noncompliance cases.

* * * *

Our principal recommendation is that since each alternative has both advantages and disadvantages that EPA not make any substantive change to the proposed financial responsibility regulations. Instead, EPA can examine current practice in a little greater depth and issue extensive technical guidance to EPA regional offices and state agencies regarding the operation and most appropriate or effective use of each mechanism. This approach will address EPA's concern with preventing those cases of improper abandonment related to insufficient funds while providing operators and regulators with flexibility.

CHAPTER VI

TIMING OF ABANDONMENT

VI. TIMING OF ABANDONMENT

Industry is concerned that the proposed rules require abandonment immediately upon cessation of operations and that such a requirement may be costly. Consequently, EPA requested that we examine the need for requiring immediate abandonment. Although we found that the rules do not specifically require immediate abandonment, nevertheless, we evaluated such a requirement and developed and evaluated alternatives.

1. ANALYSIS OF IMMEDIATE ABANDONMENT

The objective of an immediate abandonment requirement would be to assure proper abandonment. Based on historical practice, it is apparent that even with governmental regulation, operators may improperly abandon wells. A requirement for immediate abandonment would ease the regulatory agency's conduct of surveillance and enforcement and would reduce the possibility of loss of information on well location and status. It also would promote consistency among state programs. Finally, by promoting proper abandonment it would reduce the potential of long-term groundwater contamination.

However, we found at least three technical and economic disadvantages to such a requirement. First, it would preclude the conversion of injection wells into valuable observation wells. Second, it would not allow the pressure stabilization necessary to assure the safety of the abandonment crew and proper cementing. Finally, it increases the operator's potential for economic loss and may interfere with needed mineral and energy production. For example, it might preclude temporary capping of geothermal wells or temporary cessation of production from stripper wells.[1]

2. EVALUATION OF ALTERNATIVES

Exhibit VI-1 summarizes the advantages and disadvantages of the alternatives. The most attractive alternative is the first one which acknowledges the distinction between temporary

1 [illegible] stripper well [illegible]

EXHIBIT VI-1
Timing: Alternatives to Immediate Abandonment

ALTERNATIVES	ADVANTAGES	DISADVANTAGES
Set Time Period For Renewing Operations or Abandoning	. Reduces Potential For Operator Economic Loss . Assures Eventual Closing By Setting Plugging Date . Can Supplement Reporting, Testing, Or Monitoring Requirements	. Imposes Higher Surveillance Work-load Than Immediate Abandonment . Marginally Increases Possibility of Improper Abandonment
Mechanical Integrity Test	. Identifies Well Deterioration Which Requires Immediate Abandonment . Can Supplement Other Alternatives . Reduces Potential For Economic Loss	. Requires Periodic Testing Which May Impose Significant Cost . Increases Likelihood of Improper Abandonment If Not Accompanied By Specific Abandonment Date
Self Reporting	. Keeps Agency Informed Of Well Location, Ownership, And Status . Reduces Potential For Economic Loss . Can Supplement Other Alternatives	. Increases Regulatory Agency Surveillance Workload . Increases Likelihood Of Improper Abandonment
Monitoring Of Water Level Or Aquifer	. Can Provide Useful Scientific Data . Reduces Potential For Loss Of Recoverable Energy Or Minerals	. Can Be Costly, Does Not Provide Data On Environmental Impacts Of Improper Abandonment . Creates Burdensome Surveillance Workload . Increased Likelihood Of Improper Abandonment

cessation of operations and permanent abandonment. This type of mechanism currently is in use in at least Kansas, Illinois, Michigan, Texas, and Utah. The regulations in these states set a maximum time period within which the operator must either recommence operation or abandon the well. Usually, the regulations provide for extensions. Each of the three other alternatives has the advantage of easily supplementing the first alternative. However, when used alone, they can significantly increase the regulatory agency's surveillance work load as well as the long-term possibility of imporper abandonment.

APPENDIX A

STATE PLUG SETTING REQUIREMENTS

STATE PLUG SETTING REQUIREMENTS

1. <u>CALIFORNIA</u>

   . Inside casing: cement plug across producing zone and minimum of 100 feet above each zone

   . Plug above shoe or intermediate casing and from 100 feet above to 100 feet below base of fresh-water strata.

2. <u>ILLINOIS</u>

   . Complete plugging preferred; otherwise, place cement plug opposite producing zone to 20 feet above

   . If partially cased, place plug from below casing seat to 20 feet above

   . Special requirements for protecting coal seams

   . Plug 10 feet below surface casing to 15 feet above base; cut off surface 2 feet below ground and cap with cement.

3. <u>KANSAS</u>

   . Plug from bottom of well to top of each formation with a 25 foot minimum at top of fresh-water strata

   . Fill rest of hole with drilling mud.

   . Place cement plug on top of surface casing.

4. <u>KENTUCKY</u>

   . Different requirements for wells drilled through coal and non-coal bearing strata.

5. LOUISIANA

- 100 feet minimum across perforated interval
- 100 feet minimum plug from 50 feet below shoe of surface casing to 500 feet above
- 100 feet below deepest fresh water sand to at least 150 feet above sand base
- 30 foot plug in top of surface casing
- 2 foot cut off space to be filled with mud; unplugged portions of well to be filled with mud.

6. MICHIGAN

- Case by case as specified by state supervisor of wells
- Plugging must confine oil, gas, or water to the formation in which it occurs.

7. NEW YORK

- Department of State witnesses placement of cement plug from bottom of hole to 15 feet above shallowest producing formation
- 15 foot plug to be placed at bottom of any casing left in hole and about 15 feet below deepest potable water sand
- Intervals filled with mud.

8. OHIO

- Fill hole to above producing zones with seasoned wood plugs driven on top of filler
- Fill to 100 feet above plug, placing wooden plug or iron ball on casing seat after withdrawal of casing
- Cover with 50 feet of rock sediment or prepared clay
- Seal coal seams from 50 feet below seam to 20 feet above, with wooden plug placed on top and hole filled for an additional 30 feet.

- A well through a mine must leave casing from 30 feet below mine floor to 15 feet above roof.

- Finish with concrete from 100 feet below mine to top of casing with wooden plug at lower point and at top of casing, and another 20 feet of concrete placed on top of wooden plug.

9. OKLAHOMA

- Uncased hole: cement plugs 50 feet below each producing zone to 50 feet above base and from a point 50 feet below top of formation to 50 above top of the zone.

- Cased and cemented producing zone: bridge plug capped with 10 feet of cement set at top of formation.

- All fresh-water strata to be protected by a cement plug 50 feet below and 50 feet above casing shoe.

- All uncased holes to be filled with cement to at least 50 feet above casing shoe.

10. PENNSYLVANIA

- Wells not underlain by coal seams: fill with sand dumpings or mud from bottom of well to a point 20 feet above top of lowest production zone, then cement plug for at least 20 feet.

- Repeat fill procedure for 20 feet above highest production stratum.

- Place a bridge about 30 feet below water casing and a 10-foot cement plug on top of bridge. Withdraw casing and plug from 30 feet below surface casing with mud or sand dumpings.

- Wells passing through coal seams: plug production zones as above. Place a plug 10 feet below bottom of smallest coal protecting string and fill hole with 20 feet of rock or gravel.

- [illegible]

- [illegible] sand dumpings, then with [illegible]

11. TEXAS

- Place 100 foot cement plug immediately above the uppermost perforated zone or production horizon.

- If perforated screen or liners cannot be removed, place plug across zone to 100 feet above top of liner.

- If production casing is removed, place cement plug from 50 feet below surface casing shoe to 50 feet above.

- For exposed fresh-water horizons, protect with cement plug from 50 feet below base of lowest sand to 50 feet above top of sand.

- Check plug for location by landing.

- Place 10-foot cement plug at surface.

- Use mud of 9.5 lbs./gal. or better in other sections of well.

12. WEST VIRGINIA

- Fill or bridge and fill the well to a point 20 feet above the top of the lowest producing stratum

- Place a sealing plug of cement of other suitable material

- Continue to fill or bridge and fill in a similar fashion for all other strata

- Anchor a final plug approximately 10 feet below the bottom of the largest casing and fill to the surface with mud, clay, or other nonporous material

- (Regulations for wells drilled through workable coal beds differ with respect to plug placement).

13. WYOMING

- Case-by-case according to Rules 312-315 of Wyoming Oil & Gas Conservation Commission. Specifically, the well must be plugged in a manner sufficient to protect all fresh water bearing formations and possible or probable oil or gas bearing formations.

APPENDIX B

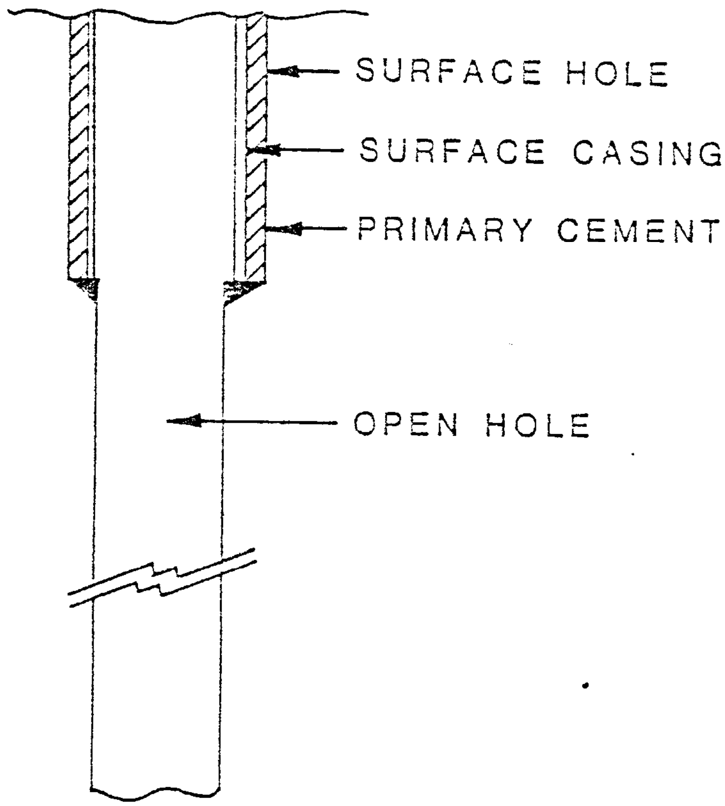
TYPICAL WELL CONFIGURATIONS

TYPICAL WELL CONFIGURATIONS

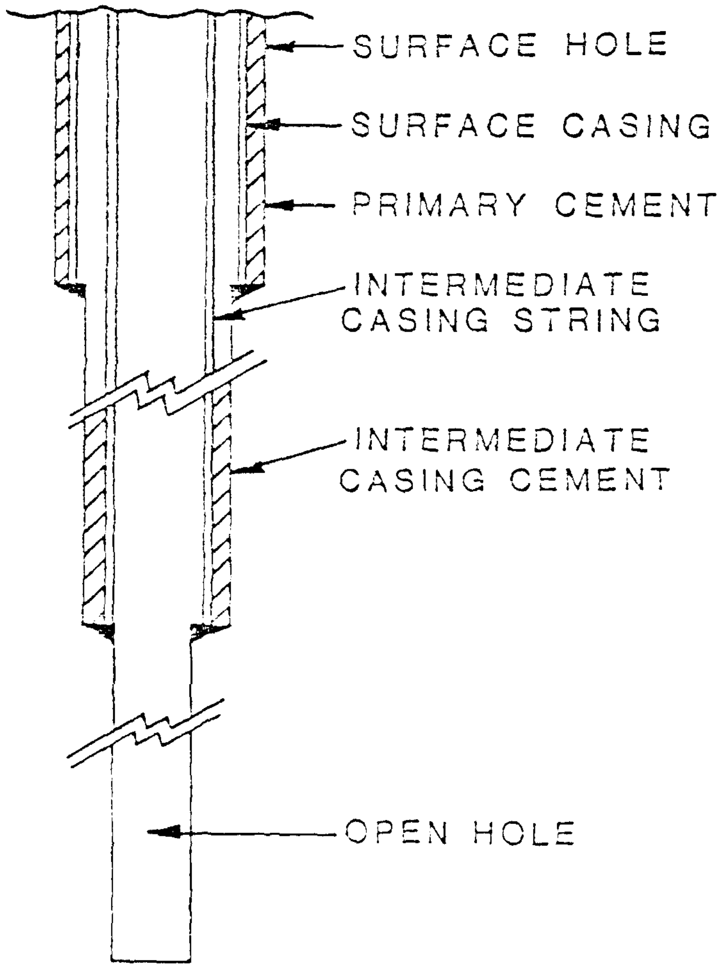
There are at least four different well configurations encountered during plugging for abandonment:

- Open hole with surface pipe cemented
- Open hole with surface pipe cemented and intermediate string set
- Production casing cut off
- Two intermediate strings and liner.

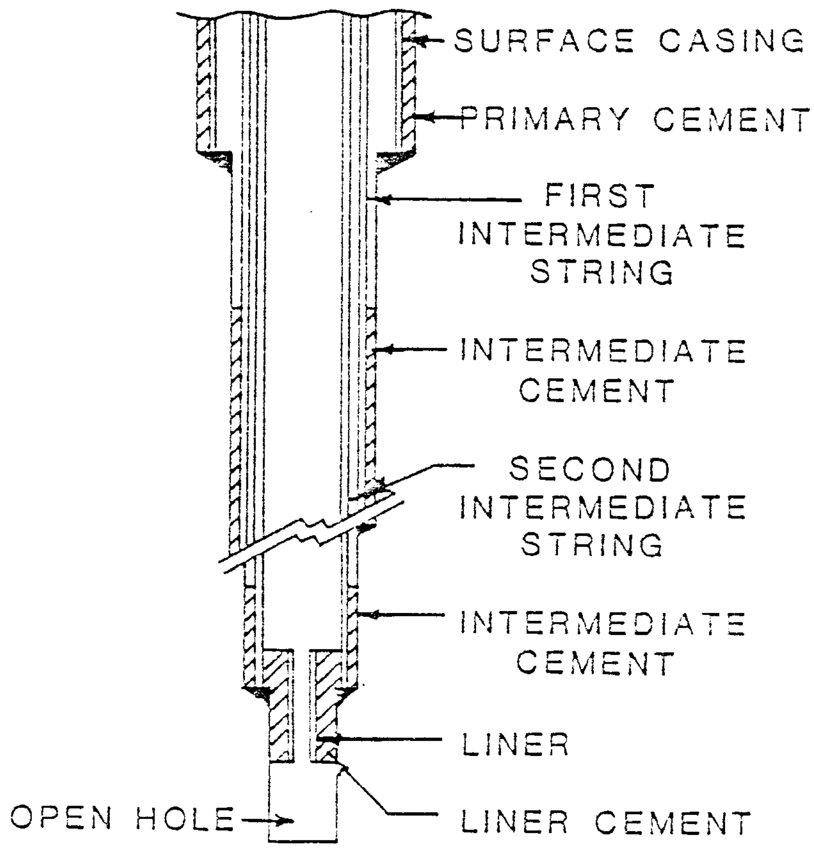
This appendix exhibits each of these configurations.



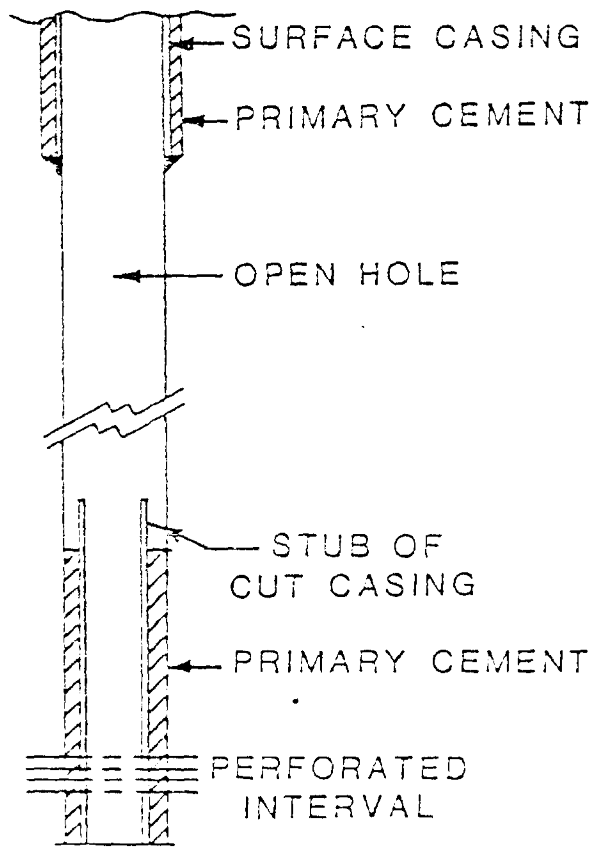
A-1. Open Hole With Surface Pipe Cemented



A-2. Open Hole With Surface Pipe Cemented
and Intermediate String Set



A-3. Two Intermediate Strings and Liner



A-4. Production Casing Cut Off

APPENDIX C

EVALUATION OF AQUIFER RESTORATION METHODS

6. METHODS OF AQUIFER RESTORATION*

As used here, restoration means the reduction of the concentrations of dissolved minerals, within the leaching field and in adjacent affected portions of the aquifer, to an acceptable level, based on regulatory considerations. Several techniques are being used or have been proposed to achieve restoration. Thus far, however, efforts have been limited to pilot-scale projects. Experience and consideration of geochemical and geological principles indicate that restoration of all elements and parameters to baseline levels will be very difficult, if not impossible. However, restoration based on water use, appears to be possible.

6.1 GEOCHEMISTRY OF AQUIFER RESTORATION

In-situ leach mining takes place in an environment of complex mineralogy. All of the common trace elements associated with the ore body are susceptible to solubilization, which is likely to occur as a result of oxidation, complexation, or replacement reactions under favorable chemical conditions. The major elements, such as sodium, calcium, magnesium, and iron can be put into solution by common dissolution or replacement reactions or ion-exchange reactions brought about by direct contact of the host rock minerals with injected lixiviant agents, or by contact with chemical agents formed within the ore body during leaching.

The mobility of an element in the in-situ mining environment is defined in terms of the tendency for lixiviant waters to transport significant concentrations of the element over some distance. The usual mode of transport is as stable, soluble ions or ionic complexes. Mobility will depend upon: (1) the pH of the lixiviant, (2) the type of complexing agent introduced by the leaching solution, and (3) the efficiency of the natural geochemical traps capable of purging minor and trace amounts of deleterious elements from the lixiviant.

The extent of aquifer contamination may be controlled by selecting lixiviants that are effective on uranium but that minimize the dissolution of associated trace elements. As a general rule, more trace elements will be mobilized by acid lixiviants than by base lixiviants.

Lixiviants are prepared with salts known to form stable aqueous complexes with uranium, however, some will also stabilize unwanted trace elements. For example, ammonium bicarbonate/carbonate lixiviants form stable aqueous amine complexes with environmentally sensitive arsenic, copper, zinc, cadmium, and mercury. Such complexation may retard the effectiveness of natural geochemical mechanisms that purge a lixiviant of these contaminating trace elements. A similar problem may arise with the oxidant used. Chlorites and chlorates, for example, introduce chloride ion which complexes readily with heavy metals.

Natural geochemical traps are likely to restrict the mobility of contaminating elements. Reprecipitation and [illegible] to [illegible] carbonate, sulfate, [illegible], [illegible], [illegible], [illegible],

* [illegible]

and vanadium, whereas adsorption is most effective with the common heavy metal trace elements. These mechanisms can purge ground water of significant amounts of contaminating ions.

Once solution mining has started, the mined aquifer will remain in an oxidizing state until reducing conditions are re-established. The mere termination of lixiviant injection may have negligible short-term effects. Migration of contaminated waters outside the immediate mining-affected area will bring the dissolved metal complexes into contact with reduced and less altered rock where reduction and precipitation of dissolved chemical species are likely to occur. The transition metals susceptible to reduction reactions will be purged from solution in preference to the stable alkali, alkaline earths, and halogens. It is important to note that these reactions are analogous to reactions responsible for the deposition of ore and associated minerals described elsewhere in this report. Indeed, redeposition has been observed where uranium-bearing lixiviants have come into contact with reduced sandstones on the periphery of a producing well field.

Table 6.1 lists the common elements susceptible to mobilization by both mildly acid and alkaline lixiviants during in-situ leach mining and cites the mechanisms likely to limit their mobility. Four mechanisms are included for purposes of comparision: (1) reprecipitation reactions as a result of solubility consideration, (2) ion exchange with common clays, (3) adsorption onto hydrous iron and manganese oxides, and (4) chemical reduction by means such as contact of solution with more reducing strata. The table is not intended to be absolute; reactions that are questionable or effective only under very specific conditions were purposely omitted.

6.2 EVALUATION OF RESTORATION TECHNIQUES

Techniques of leach field restoration that have been attempted or proposed are: (1) pumping of selected leach field wells; (2) pumping of selected leach field wells in combination with injection into other selected wells of natural ground water, recirculated treated leach field water, or one of the above types of water with chemicals added; and (3) natural restoration. In evaluating these techniques, it must be realized that, as previously mentioned, the only existing experience with leach field restoration is at the pilot project level. Some problems with extrapolating pilot-scale restoration results to production-scale operations therefore exist. First, the geologic and geochemical framework of the pilot-scale operations may be different. For example, a pilot-scale project might be entirely within and surrounded by an ore body, whereas the production-scale operation would be expected to extend to the limits of the ore body. Second, a pilot-scale operation, because of its small size (typically only a single five-spot array of wells), would not be expected to encounter the stratigraphic variations that will commonly be found over the area of a production-scale operation.

TABLE 6.1

NATURAL MECHANISMS LIMITING MOBILITY OF ELEMENTS IN MILDLY ACID AND ALKALINE LIXIVIANTS

Mechanism	Elements Immobilized
Mildly Acid Lixiviants	
Reprecipitation	S(SO_4^{-2}), Mo, Se, As, V, Ba, Ra
Ion Exchange	Na, Ca, Mg, N(NH_4^{+}), U, V
Adsorption	S(SO_4^{-2}), Mn, Mo, Se, As
Reduction	S(SO_4^{-2}), U, Fe, Mo, Se, As, Cu, Pb, Zn, Cd, Hg
Mildly Alkaline Lixiviants	
Reprecipitation	Ca, Mg, C(CO_3^{-2}), S(SO_4^{-2}), U, Fe, Mn, Se, As, V, Cu, Pb, Ba, F, Ra
Ion Exchange	Na, Ca, Mg, N(NH_4^{+}), U, V, Cu, Pb, Zn, Hg
Adsorption	S(SO_4^{-2}), U, Mn, V, Cu, Pb, Zn, Ra, Cd, Hg
Reduction	S(SO_4^{-2}), U, Fe, Mo, Se, As, Cu, Pb, Zn, Cd, Hg

6.2.1 Pumping of Selected Leach Field Wells

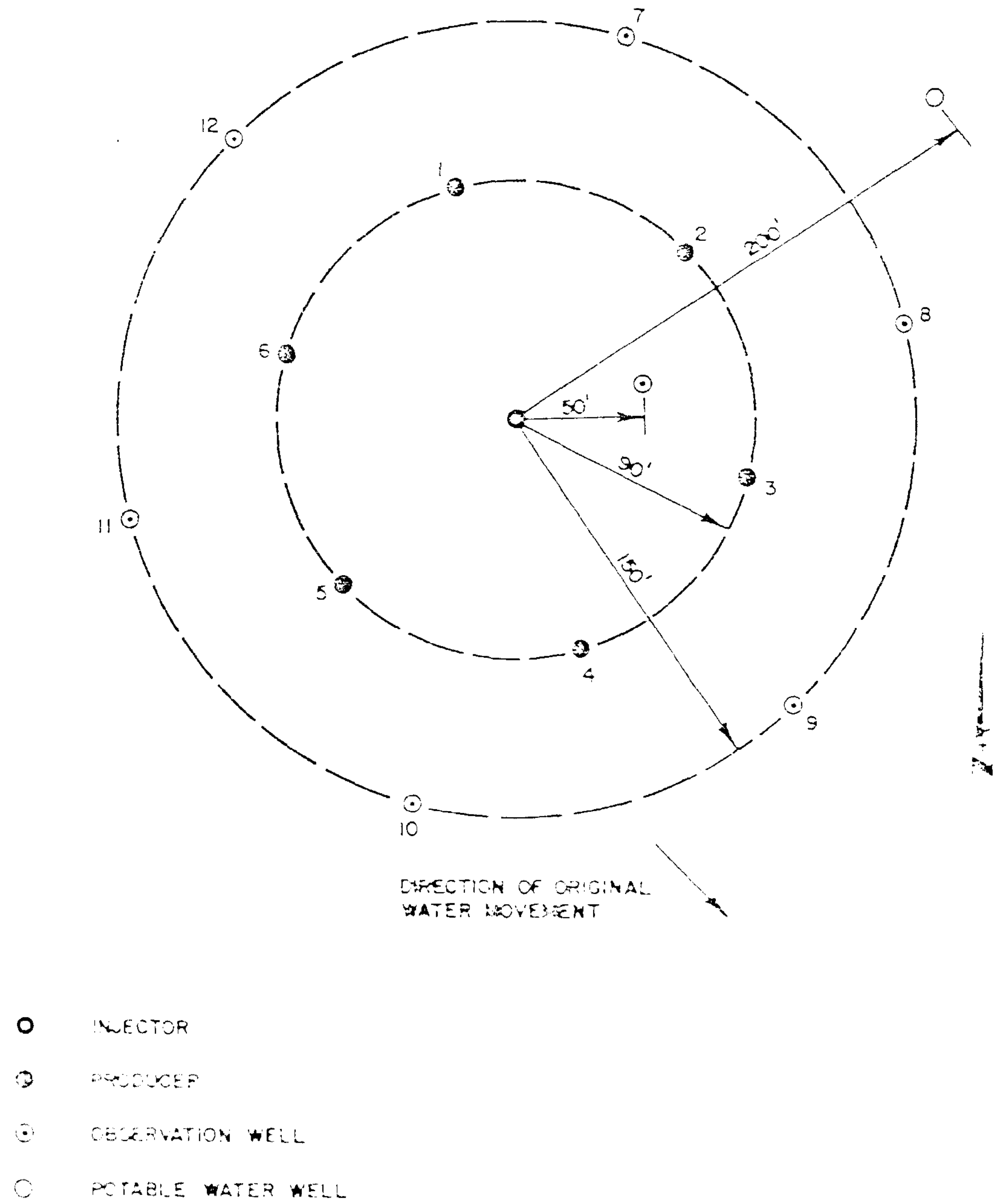
The initial concept of leach field restoration, as developed in Texas, involves only the pumping of selected leach field wells after cessation of lixiviant injection. The pumping is intended to draw uncontaminated ground water from outside the leaching field to displace the injected lixiviant and the constituents mobilized by it. Under ideal conditions, it is believed that ground water from outside the leaching field will completely displace the lixiviant, thus producing a water-quality condition that is the same as average baseline quality.

The best data examined for restoration by pumping alone are those obtained by the Exxon Company at the Highland Uranium Mine.[1] The pilot project involved a single injection well surrounded by six producing wells (Figure 6.1) and a single ring of six monitor wells. The ore bearing sandstone at the site averages 23 feet in thickness and has a porosity of 29 percent.[1] Based on this thickness and porosity, the pore volume within the ring of production wells is about 1.27 million gal (4,800 m^3) and within the ring of monitor wells is about 3.53 million gal (13,350 m^3). Because excursion beyond the ring of production wells did occur during mining, it can only be concluded that the aquifer volume affected by mining was greater than 1.27 million gal, but less than 3.53 million gal.

During mining of the pilot project, 11.55 million gal (43,890 m^3) of lixiviant ($NaHCO_3$ and O_2) were injected and 10.29 million gal (39,100 m^3) were withdrawn, leaving 1.26 million gal (4,770 m^3) in place when injection ceased on November 4, 1974. After injection of lixiviant ceased, pumping of the six production wells continued and pumping of the injection well began. Aggregate production from the seven wells averaged about 21,000 gpd (80 m^3/day).

It is not known what the uranium concentration was in the produced pregnant lixiviant during well-field operation, but it would be expected to be in the hundreds of mg/l, in contrast to the baseline uranium values which were less than 1 mg/l. By October 26, 1977, after production of about 22.7 million gal of water (Table 6.2 and Figure 6.2), the uranium concentration in water produced from the former injection well was 61 mg/l and concentrations were from 9 to 33 mg/l in the production wells. Figure 6.2 shows an irregular, but clear, tendency toward reduction in uranium concentration in the water produced from the injection well until late 1977, although uranium levels at that time were still more than 100 times the original average baseline value of 0.2 mg/l (Table 6.3).

The restoration of other parameters including carbonate, bicarbonate, radium-226, thorium-230, arsenic, and selenium was evaluated. Inspection of available data, without a rigorous statistical analysis, shows that both carbonate and bicarbonate levels remained very high in water samples from the injection well until April 1977, when the levels of both declined rapidly, with the bicarbonate level reaching baseline (Tables 6.4 and 6.5). Radium-226 was originally high (120 pCi/l) and has remained in


7
12
1
2
200'
8
6
50'
90'
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11
150'
5
4
9
10
DIRECTION OF ORIGINAL
WATER MOVEMENT
INJECTOR
PRODUCER
OBSERVATION WELL
POTABLE WATER WELL

Figure 6.1. [illegible]

TABLE 6.2
URANIUM CONCENTRATION DURING RESTORATION,
HIGHLAND SOLUTION MINE PILOT1)

Date	Observed Uranium Concentrations Milligrams Per Liter By Well					
	1	2	3	4	5	6	INJ.
08/19/76	34	72	9	14	57	60	157
09/25/76	–[1]	62	6	12	-	52	165
10/11/76	-	49	5	9	-	-	111
10/19/76	-	62	10	15	-	46	145
10/29/76	8	54	13	16	-	50	133
11/04/76	7	52	6	13	-	46	131
11/15/76	6	42	11	15	-	42	126
11/24/76	19	60	13	14	14	48	134
12/03/76	16	42	11	12	31	41	135
12/07/76	24	44	7	11	37	39	129
12/20/76	20	54	10	11	45	42	139
01/13/77	12	-	13	-	47	48	129
01/30/77	27	-	6	-	60	49	112
02/14/77	27	-	6	-	60	49	103
03/01/77	27	33	10	-	61	54	121
03/12/77	31	38	21	-	21	42	54
03/25/77	18	37	50	-	24	19	89
04/21/77	31	47	24	-	59	-	94
04/26/77	17	37	5	-	42	31	73
05/21/77	36	55	28	-	69	-	110
06/23/77	11	31	5	-	42	39	68
07/21/77	10	32	-	-	32	31	54
08/04/77	9	31	1	-	28	-	54
09/25/77	3	31	3	-	-	31	57
10/26/77	14	26	9	-	-	33	61

1/ Dash indicates well not producing, and no sample was taken on that date.

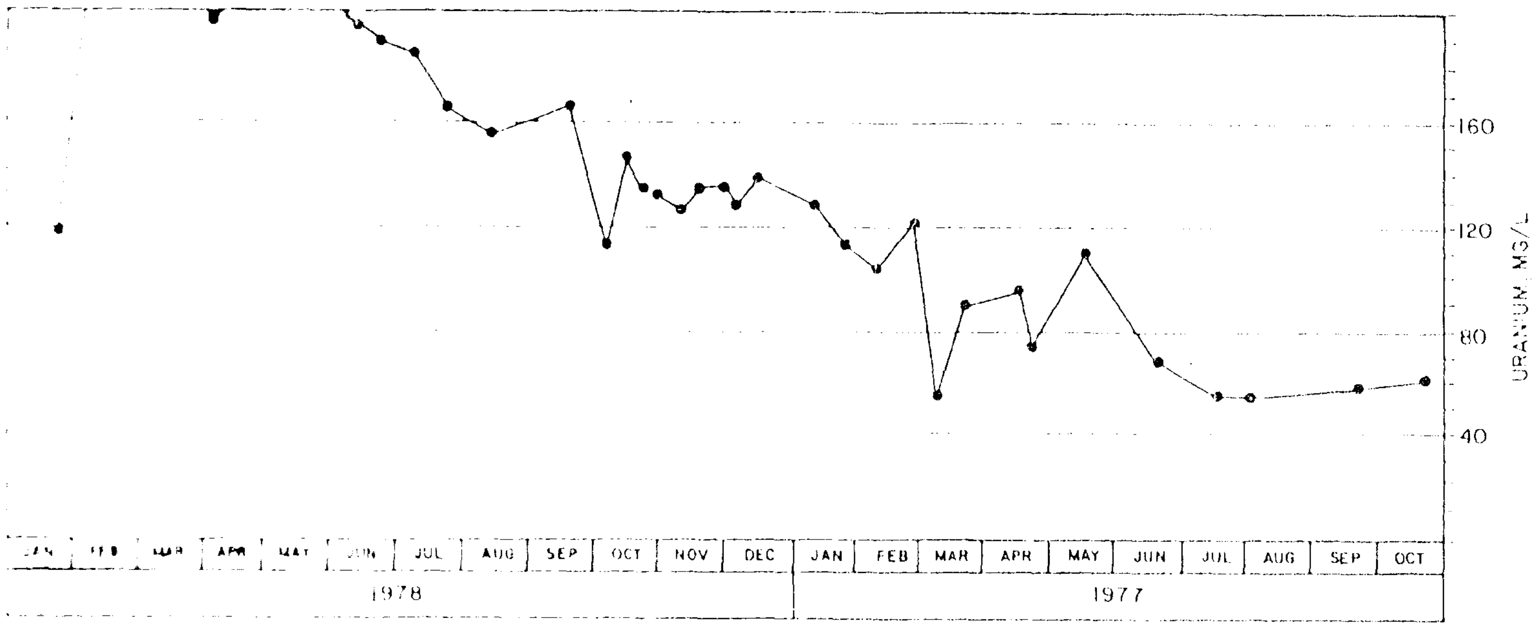

Figure 6.2. Uranium concentrations in the produced fluid during restoration by the "sweeping" method, Exxon's Highland Pilot Project.[2]

TABLE 6.3
ORE-ZONE BASELINE WATER QUALITY,[1/]
HIGHLAND SOLUTION MINE PILOT1)

Parameter	Value
Sodium	161 ppm
Calcium	77 ppm
Magnesium	13 ppm
Chloride	27 ppm
Sulfate	119 ppm
Bicarbonate	237 ppm
Selenium	<0.5 ppm
Uranium	212 ppb
Radium 226	1.2×10^{-7} uCi/ml
Thorium 230	8.6×10^{-8} uCi/ml

[1/] Average of 3 samples taken from 3 production wells in original pilot area during May 1970.

TABLE 6.4
CARBONATE CONCENTRATIONS DURING RESTORATION,
HIGHLAND SOLUTION MINE PILOT[1)]

	Observed Carbonate Concentration Milligrams Per Liter By Well						
Date	1	2	3	4	5	6	INJ.
08/19/76	51	181	0	42	51	173	554
09/25/76	–	163	0	23	–	209	650
10/11/76	–	147	2	–	–	–	505
10/29/76	0	165	0	11	–	143	569
11/04/76	–	174	34	33	–	152	535
11/24/76	11	161	0	11	0	97	550
12/07/76	48	145	16	48	11	0	469
12/20/76	24	167	24	24	24	71	547
01/30/77	70	–	11	–	34	139	550
02/14/77	47	–	0	–	6	104	485
02/27/77	0	258	11	–	47	–	469
03/06/77	50	71	0	–	14	50	264
02/25/77	20	22	0	–	0	7	242
04/21/77	30	60	0	–	10	40	20
04/26/77	0	86	0	–	21	[illegible]	21

TABLE 6.5

BICARBONATE CONCENTRATIONS DURING RESTORATION, HIGHLAND SOLUTION MINE PILOT[1)]

	Observed Bicarbonate Concentration Milligrams Per Liter By Well						
Date	1	2	3	4	5	6	INJ.
08/19/76	512	849	157	353	506	792	1,503
09/25/76	-	495	142	355	-	520	1,511
10/11/76	-	619	255	-	-	-	1,233
10/29/76	236	418	259	351	-	489	1,275
11/04/76	165	472	178	311	-	495	1,145
12/07/76	220	477	145	187	207	477	1,224
12/20/76	387	676	290	338	436	556	1,718
01/30/77	311	-	228	-	456	519	1,494
02/14/77	328	-	234	-	517	434	774
02/27/77	332	519	199	-	519	477	1,286
03/06/77	181	226	113	-	266	226	447
03/25/77	147	194	68	-	158	136	520
04/21/77	119	201	174	-	174	146	137
04/26/77	90	271	102	-	254	226	243

the range of 50 to 100 pCi/l during the restoration phase (Tables 6.6). There does not seem to have been a clear trend toward reduction in the level of arsenic during the restoration period, but selenium levels appear to have decreased during restoration (Table 6.7).

It can be concluded that pumping for the purpose of drawing in natural ground water does produce a trend of water-quality improvement, but it can be very time consuming, and perhaps impossible, to bring the levels of all elements of concern back to within the original baseline range. Furthermore, the volume of water pumped to produce significant improvement in quality was large, and handling of such volumes of water would be a major waste-disposal problem during a full-scale project.

Pilot leaching projects using an alkaline leach, with the exception of the Exxon test, have used ammonium bicarbonate in the lixiviant. The use of ammonium has caused a special restoration problem. Figure 6.3 shows the results obtained by Wyoming Mineral Corporation during restoration by pumping alone at that company's Irigaray site.[3,4] The pumping or "ground-water sweep" test was a single-well test, and, thus, particularly unrepresentative of a production-scale effort. However, the inability of pumping alone to lower the ammonium level is typical of other such test data that have been examined. The total dissolved solids were restored to below baseline, but many of the individual parameters, in addition to ammonium, remained at many times the initial values measured in the 517-well area (Table 6.8).

The three principal reasons why pumping alone is only partly successful, as evidenced by available data, are:

(1) Sandstone bodies of the type in which uranium leaching is being practiced are naturally inhomogeneous and commonly include preferred paths of fluid flow. During restoration by pumping, it is expected that inflowing ground water will readily sweep contaminated water from the areas through which flow is preferentially channelled, but will bypass contaminated water in other areas. As restoration continues, water that was originally bypassed will be slowly removed.

(2) Some ions, of which ammonia is an extreme example, adsorb to minerals (particularly clays) in the aquifer. During leaching, these minerals are present in the water in relatively high concentrations. During restoration, as the amounts in solution decrease, the ions begin to desorb. The desorption process can be very slow, resulting in the presence of the desorbing ion for a long period of time.

(3) Prior to mining, water in contact with minerals in and around the uranium ore body is expected to have reached the state of chemical equilibrium with the minerals. During leaching, the existing chemical equilibrium will be disturbed and it may be difficult, [illegible], to reestablish it.

TABLE 6.6
RADIUM AND THORIUM CONCENTRATIONS DURING RESTORATION, HIGHLAND SOLUTION MINE PILOT[1])

Date	Radium 226 ($\mu Ci/ml \times 10^{-8}$)	Thorium 230 ($\mu Ci/ml \times 10^{-7}$)
05/01/70[1/]	12.0	0.86
07/04/72	9.2	39.5
09/04/72	1.1	21.0
01/19/73	21.4	68.1
05/10/74	110.0	1040.0
08/05/74	-	42.0
11/12/74	40.0	280.0
02/04/75	8.8	67.0
05/02/75	4.4	1.6
06/08/75	12.5	0.5
09/03/75	6.8	1.2
10/02/75	10.0	0.3
11/03/75	14.0	3.6
12/01/75	9.0	4.3
01/05/76	8.2	20.4
02/03/76	12.2	3.4
03/01/76	8.2	0.3
04/05/76	5.2	0.1
05/03/76	7.9	1.3
06/04/76	8.6	0.9
07/02/76	5.9	0.7
08/02/76	6.4	0.9
09/01/76	5.6	1.0
10/13/76	7.3	1.4
11/09/76	7.7	2.1
12/01/76	5.6	1.0
01/03/77	7.4	.7
02/01/77	7.6	1.2
03/04/77	9.2	1.4

1/ Average of 3 samples taken prior to solution mining operations.

TABLE 6.7
ARSENIC AND SELENIUM CONCENTRATIONS
DURING RESTORATION,
HIGHLAND SOLUTION MINE PILOT[1]

Date	Arsenic (mg/l)	Selenium (mg/l)
May 1970[1]	-	<0.5
09/03/75	0.36	0.17
01/05/76	0.38	0.14
02/03/76	0.37	0.17
04/05/76	0.33	0.16
05/03/76	0.36	0.17
06/04/76	0.44	0.21
07/02/76	0.31	0.14
08/02/76	0.28	0.08
09/01/76	0.40	0.13
12/01/76	0.09	0.05
01/03/77	0.23	0.10
02/01/77	0.32	0.08
03/04/77	0.21	0.08

[1] Sample taken in pilot area prior to initiating solution mining test.

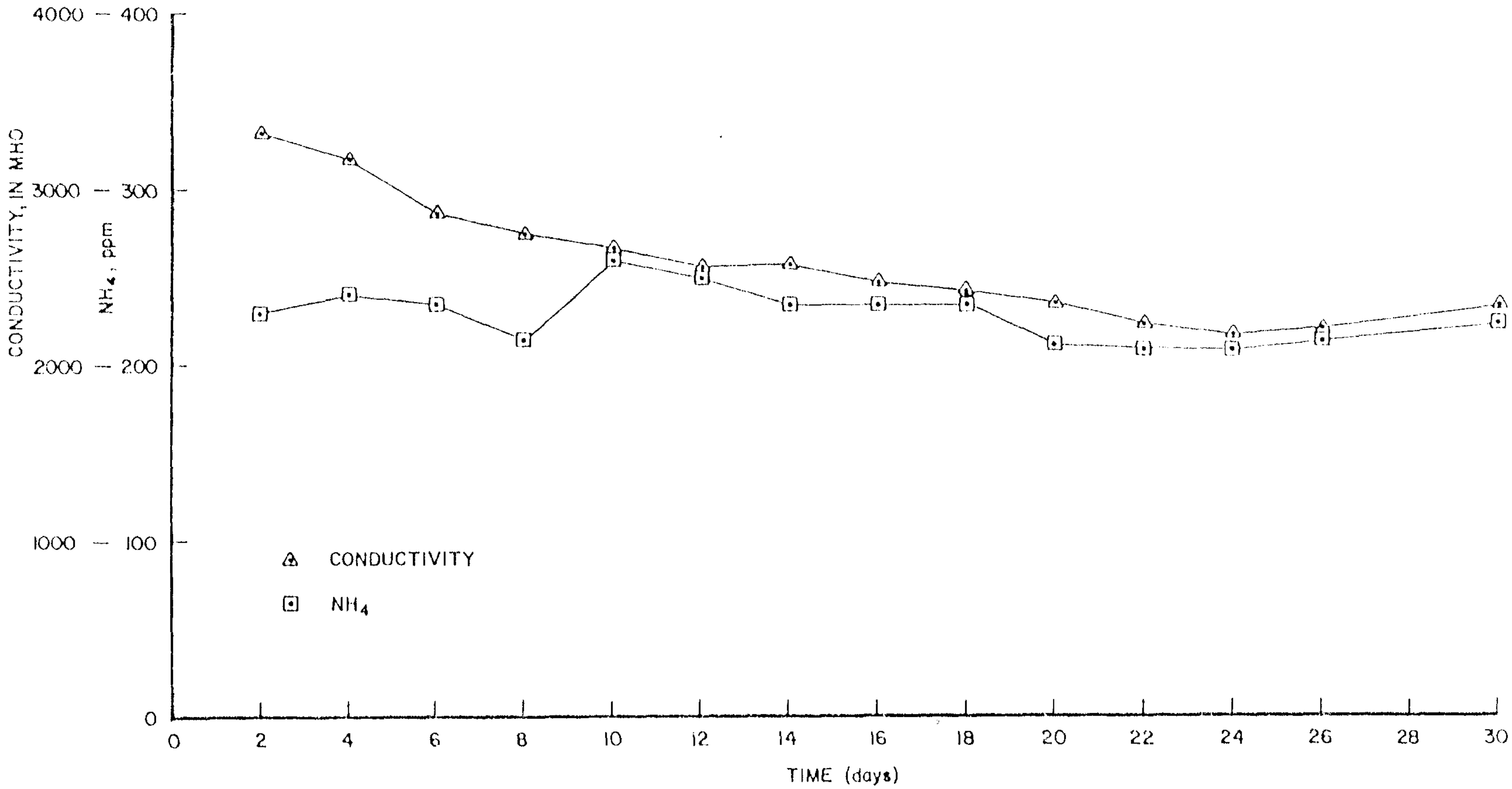

Figure 6.3. Ammonia concentrations and specific conductivity in the produced fluid during restoration by the "ground-water sweep" method, Wyoming Mineral's Irigaray Pilot Project.[3]

TABLE 6.8
WATER-QUALITY CHANGES RESULTING FROM
GROUND-WATER SWEEP, IRIGARAY 517-3 PILOT[3)]

	Initial (ppm)[1/]	Final (ppm)	517 Baseline[2/] (ppm)
NH_4	180	123	< 1.0
As	.033	.017	< .0025
Ba	.09	.03	.12
B	8.3	0.26	.16
Cd	0.30	< .002	< .005
Ca	58.5	13.5	---
CO_3	4.2	4.7	---
Cl	531	229.9	10.75
Cr	< .002	.004	.0135
Cond (μmhos)	3.30×10^3	1.95×10^3	---
Cu	.215	.041	.019
F	2.75	4.10	---
$CaCO_3$	616	445	232
Fe	2.15	.65	---
Pb	.32	0.58	.0035
Mg	19.5	5.4	---
Mn	.784	.150	.12
Hg	.0002	< .0002	.0028
Mo	< .02	.42	---
Ni	1.79	< .20	.015
NO_3	4.92	1.24	---
NO_2	2.76	0.151	---
pH	7.94	6.14	---
K	8.14	2.9	---
Se	1.02	.339	[illegible]
Si	5.3	3.3	---
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	---
[illegible]	[illegible]	.33	[illegible]
[illegible]	[illegible]	712	[illegible]
[illegible]	[illegible]	.21	---
[illegible]	[illegible]	12.3	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

The most effective chemical would reduce oxidized elements, and combine with them to form insoluble compounds. Sulfides, such as hydrogen sulfide or sodium sulfide, appear suitable because of their assumed chemical effectiveness, environmental compatibility, and relatively low cost. Readjustment of the reduction potential of the ground-water system is expected to have only a minor effect on the major cations and anions (Na, Ca, Mg, SO_4, HCO_3, CO_3, Cl). The injection of reducing agents is not known to have been applied in the field.

- The injection of a solution to promote rapid ammonium ion desorption has been suggested. The affinity of cations to adsorb to minerals generally increases with increasing valence and concentration. Therefore, it is expected that adsorbed ammonium ions can be displaced from clay minerals by high concentrations of multivalent ions. Bivalent calcium and magnesium ions appear to be good candidates because of their affinity to adsorb and their common occurrence in nature.

Wyoming Minerals performed a test at the Irigaray site in which a solution high in calcium, sodium, and/or magnesium was injected to desorb ammonium (Figure 6.4).[3,4] As expected, the concentration of ammonium in the recovered solution increased during injection of the ion-bearing solution from about 65 mg/l to over 200 mg/l, reflecting the increased desorption of ammonium. The concentration then decreased as the ammonium was depleted. After recovery of about 450,000 gal (1,710 m^3) of fluid, injection of water treated by reverse-osmosis was begun to remove the injected saline solution. After recovery of an additional 550,000 gal (2,090 m^3) of fluid, the ammonium level was about 35 mg/l as compared with the value of 65 mg/l before the test began. It is concluded that additional reduction in well-field ammonium values can be achieved by injection of a saline solution, but that the test failed by a considerable margin to achieve complete ammonium removal.

6.2.3 Natural Restoration

Thus far, state and Federal regulatory agencies have made pumping or a combination of pumping and injection the required means of leaching field restoration. No study has yet been made to determine what the result would be if reliance were placed upon the natural capacity of the ore-bearing stratum and uncontaminated ground water to restore or partially restore the affected area.

The concept of natural ground-water quality restoration may have particular merit in uranium leaching. It is believed that, under the proper circumstances, most of the objectionable elements that have been introduced or mobilized during leaching will be removed by reprecipitation, ion exchange, adsorption, or reduction, as discussed earlier in the introduction to the section.

Problems associated with the concept of natural restoration include the difficulty of predicting (1) the time and distance required for the contaminant removal processes to be effective, (2) the degree of

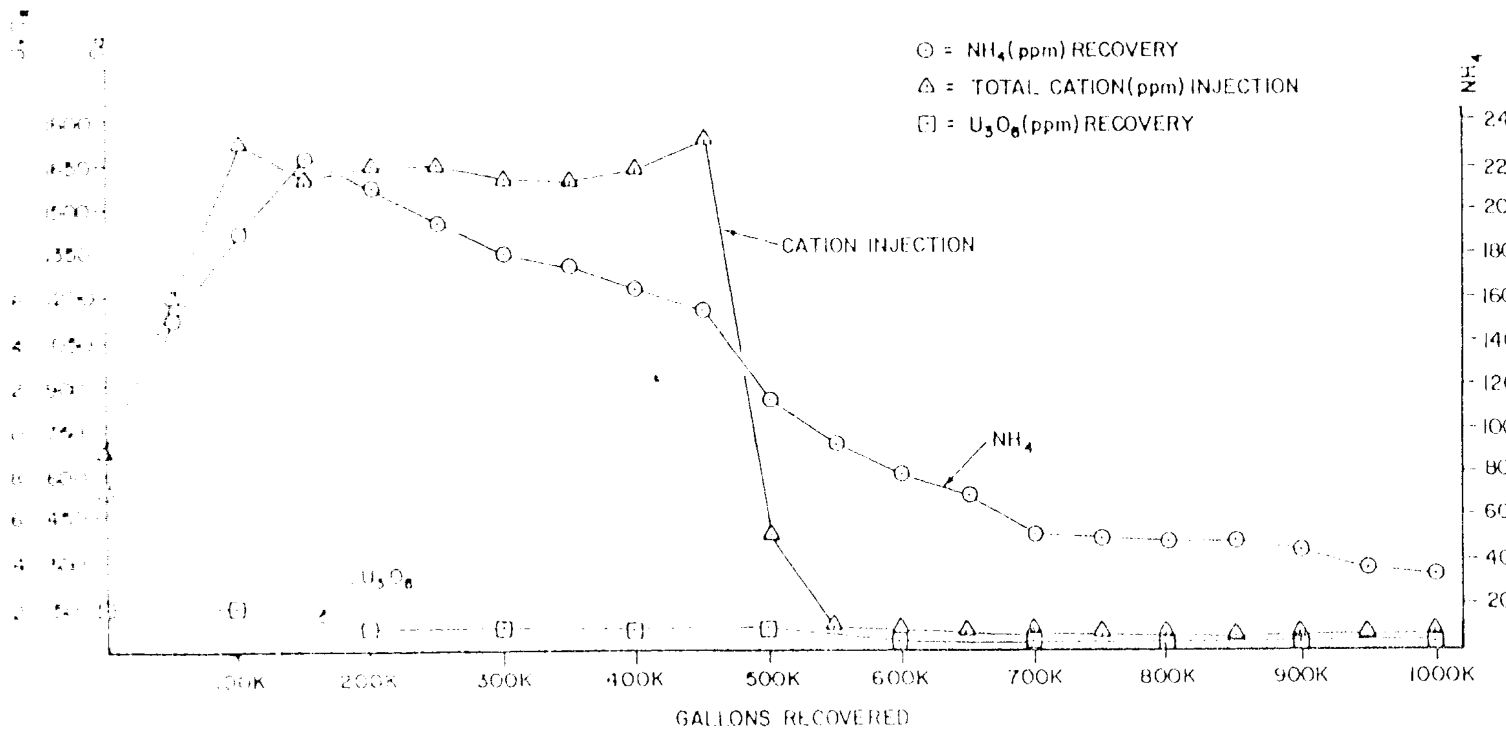

Figure 6.4. Ammonia changes in well-field fluid quality during restoration using injection of cation solution.

6.2.2 Pumping in Combination With Injection

Restoration could be expedited by simultaneously pumping selected wells and injecting water that has been tailored by pretreatment and/or chemical addition into other wells. Pumping would draw out the injected lixiviant and mobilized ions, while injection would drive the contaminated water toward the pumping wells.

6.2.2.1 Injection of Natural Ground Water

Injection of natural ground water is perceived to have no advantages over pumping alone. Pumping alone draws in natural ground water without the added cost and technical difficulty of injection. In fact, if the injected water were to contain oxygen, it would be expected to have a negative effect by sustaining the mobilization of uranium and other oxidizable elements. For example, 1 mg/l of dissolved oxygen is capable of oxidizing 17.5 mg/l of U_3O_8.

6.2.2.2 Injection of Treated Leach Field Water

One of the major problems associated with restoration by pumping alone is the disposal of the contaminated water brought to the surface (Section 7) Treatment of pumped water, for reduction of some or all of the contaminants, and reinjection of the treated water to the well field reduces the volume of contaminated water that must be disposed. A variety of partial or complete treatment methods are available. For example, partial treatment might consist of uranium stripping and precipitation of radium-226. Complete treatment by one of the deionization methods, such as reverse osmosis, may be utilized where partial or selective treatment is precluded.

Wyoming Mineral Corporation is the only company known to have experimented with injection of treated well-field water. At its Irigaray, Wyoming site, water produced from the well field was run through a reverse-osmosis unit and reinjected during the "clean water recycle" test. The effectiveness of the reverse-osmosis treatment of produced well-field water is shown in Table 6.9. It is estimated that the concentrate containing the contaminants comprised only 20 percent of the volume of water treated, thus eliminating 80 percent of the water that would otherwise have to be disposed.[3,4] Obviously, injection of the treated water will achieve a considerable reduction in the average levels of dissolved constituents by dilution.

As discussed above, injection of treated water would be expected to introduce oxygen into the ground-water system that will cause continued oxidation and mobilization of uranium and other metals, unless some form of deaeration is used prior to injection.

6.2.2.3 Injection of Water Containing Added Chemicals

An alternative restoration technique is the injection of water containing appropriate chemicals to remove uranium and trace metals from solution.

TABLE 6.9
EFFECTIVENESS OF REVERSE OSMOSIS IN WYOMING MINERALS IRIGARAY PROJECT 3)

Constituent	Concentration of constituent in mg/l[1/] Before reverse osmosis	After reverse osmosis	Percent Reduction
U_3O_8	43	< 1	> 97.6
CO_3	8	< 4	> 50.0
Cl	686.8	26	96.2
SO_4	641.8	4.3	99.3
Na	434	10.7	97.5
Ca	71.5	2.2	96.9
Mg	23.3	< 1.0	> 95.7
NH_4	54.3	2.7	95.0
pH	4.7	4.9	--
Conductivity	3,237.3 µmhos	149 µmhos	--

[1/] Constituents in mg/l except pH and Conductivity.

contaminant removal that will be achieved, and (3) the ultimate fate of some elements or ions, e.g., chloride and ammonia.

6.3 ENVIRONMENTAL IMPACTS OF RESTORATION TECHNIQUES

The uranium leaching process mobilizes varying amounts of natural uranium, thorium, arsenic, selenium, and other metals that are found in and adjacent to uranium ore bodies. In addition, leaching agents containing such chemicals as ammonia, carbonate/bicarbonate, sodium, sulfate, and chloride are added to the ground-water system.

It has been shown, in pilot restoration projects, that most of the introduced and mobilized chemicals can be significantly removed by mechanical and chemical restoration methods. It is believed that natural geochemical mechanisms, either alone or after mechanical restoration, are capable of causing significant water-quality improvement but prediction of the effectiveness of natural restoration is not now possible.

Mechanical restoration methods are time consuming, expensive, and, for geological and geochemical reasons, perhaps even incapable of returning every ion and parameter to its original baseline level. Additionally, mechanical restoration by ground-water pumping, the method most widely favored today, results in large volumes of waste water that must be handled. This may present environmental problems which are discussed in Section 7. Treatment and reinjection of pumped water produces a smaller volume of waste water, but the contaminants still must be handled at the surface in a concentrated liquid and/or solid form. In-situ restoration by chemical injection may have an advantage because no wastes are brought to the surface. This process, however, has only been proposed thus far.

REFERENCES

1. Exxon Company. Supplemental Environmental Report, Application for Amendment to Source Material License SUA-1139 for Solution Mining of Uranium. Highland Uranium Mill, Docket No. 40-8102, 1977.

2. Exxon Company. Explanatory Attachment to Application for Amendment to Source Material License SUA-1064, Docket No. 40-8064, 1978.

3. Wyoming Mineral Corporation. Irigaray Restoration Demonstration Program Final Report, Lakewood, Colorado, Docket No. 40-8304, 1978.

4. U.S. Nuclear Regulatory Commission. Draft Environmental Statement, Highland Uranium Solution Mining Project, Exxon Minerals Company, U.S.A., Docket No. 40-8012, May, 1978.

7. WASTE GENERATION AND DISPOSAL

Wastes are generated during uranium recovery and aquifer restoration, though the quality and quantity of the wastes are variable. In general, the process wastes have a low volume but a high dissolved solids content, whereas the restoration wastes are high volume and low solids. Appendix D and Section 6 discuss the process methods and restoration methods in detail.

Because most wastes will be either liquids or slurries, the following methods for disposing of wastes associated with in-situ leach mining have been evaluated: (1) disposal wells, (2) lined evaporation ponds or tailings ponds, and (3) liquid/solid separation with use of the residual water for such purposes as irrigation. Additionally, direct surface-water discharge was evaluated as a potential waste-disposal method, however, current EPA effluent guidelines prohibit the discharge to streams of any material from uranium mills.[1]

Several assumptions were made concerning the waste streams prior to making the assessment. The waste from a typical uranium recovery process (Figure 7.1) will be a liquid or a slurry of suspended solids produced at a rate of 27.9 ac-ft/yr (34.4 hm^3) [30 gpm (1.9 l/s)] or more. Table 7.1 presents a crude estimate of the chemical quality of this fluid (no complete chemical analyses are available from the industry). The restoration waste stream will be the fluid produced by the ground-water sweep restoration method. This method results in the handling of very large volumes of waste. The waste is produced at 1,300 ac-ft (1,600 hm^3) or more per year (800 gpm [50.4 l/s]) and has a chemical composition similar to that shown in Table 7.2. The quality of the recovered water will improve with time for any one area of restoration, but because two or more areas may be under restoration concurrently, only the poorer quality waste has been shown.

7.1 DISPOSAL WELLS

For a subsurface disposal system to be environmentally acceptable, it is necessary to locate a porous, permeable formation of wide areal extent at sufficient depth to ensure retention of the injected fluids. A low permeability zone should separate the injection horizon from horizons containing potable ground water and/or mineral reserves to prevent vertical migration of the wastes or displaced formation brines into these "usable" strata.[2] The disposal zone should contain water with a TDS quality poorer than 10,000 mg/l.

7.1.1 Regulatory Feasibility

All States in which in-situ leach mining may take place have a regulatory position that allows the use of disposal wells. The requirements to operate such wells differ considerably, although in general, extensive preliminary data collection and engineering safeguards are necessary. Disposal wells of any type are operating only in Texas and New Mexico.

APPENDIX D

COSTS FOR FINANCIAL RESPONSIBILITY ALTERNATIVES

COSTS FOR FINANCIAL RESPONSIBILITY ALTERNATIVES

To determine the comparative costs of the financial responsibility alternatives given in Exhibit V-2, we:

- Developed discount equations for each financial responsibility alternative
- Calculated the estimated costs of each alternative
- Determined comparative costs of alternatives.

Our methodology used a standard present value analysis and assumptions derived from discussions with operators and financial institutions.

1. DEVELOPMENT OF DISCOUNT EQUATIONS

We identified the following factors as ones that would affect the cost of each alternative:

- Duration of the demonstration of financial responsibility
- Real opportunity cost of capital
- Real internal rate of return
- Estimated annual premium or service charge of each alternative
- Expected real interest rate on each alternative.

We assigned alternative values to each of these factors, as shown in Exhibit D-1 which also displays the discount factor equations used. Using these equations, we calculated the intermediate discount factors displayed in Exhibit D-2.

2. CALCULATION OF THE COSTS OF EACH ALTERNATIVE

[illegible]

EXHIBIT D-1
Discount Equations and Assumptions

Alternative	Discount Equation	Assumptions
Financial Statement	$1/(1+r)^N$	r= 3.5, 5%, 7.5% N= 1, 5, 10, 20
Surety Bond	$[1/(1+r)^N] + [(sc)(1+r)^N - 1/r(1+r)^N)]$	r= 5%, 7.5% sc= 1% - 1.5% N= 1, 5, 10, 20
Security Bond	$[1/(1+i)^N] + [(sc)(1+r)^N - 1/r(1+r)^N)]$	i= 2% r= 3.5%, 5% sc= 2.5% - 3% N= 1, 5, 10, 20
Escrow Account	$[1/(1+i)^N] + [(sc)(1+r)^N - 1/r(1+r)^N)]$	i= 2% r= 3.5%, 5%, 7.5% sc= 1% N= 1, 5, 10, 20

Key: r= internal rate of return to the operator
N= number of years before closure
sc= annual premium/service charge
i= real interest reate on the account

EXHIBIT D-2

Intermediate Discount Factors

Discount Factor	N=1 (One Year Before Closure)	N=5 (Five Years Before Closure)	N=10 (Ten Years Before Closure)	N=20 (Twenty Years Before Closure)
[illegible]				
[illegible]	.9804	.9057	.8203	.6730
[illegible]				
[illegible]	.9662	.8420	.7089	.5026
[illegible]	.9524	.7835	.6139	.3769
[illegible]	.9302	.6966	.4852	.2354
[illegible]				
[illegible]	.9662	4.5151	8.3166	14.2124
[illegible]	.9524	4.3295	7.7217	12.4622
[illegible]	.9302	4.0453	6.8634	10.1937

EXHIBIT D-3
Costs of Financial Alternatives

Alternative	One Year Before Closure	Five Years Before Closure	Ten Years Before Closure	Twenty Years Before Closure
Financial Statements				
r = 3.5%	$9,662	$8,420	$5,969	$5,026
r = 5.0%	$9,524	$7,836	$4,810	$3,769
r = 7.5%	$9,302	$6,139	$3,380	$2,354
Performance Bonds				
Surety Bond				
r = 5.0%	$9,619-$9,667	$8,268-$8,484	$6,911-$7,297	$5,015-$5,638
r = 7.5%	$9,395-$9,442	$7,371-$7,593	$5,538-$5,882	$3,373-$3,883
Security Bond				
r = 3.5%	$10,046-$10,094	$10,186-$10,412	$10,282-$10,698	$10,283-$10,994
r = 5.0%	$10,042-$10,090	$10,139-$10,356	$10,133-$10,520	$9,846-$10,469
Escrow Accounts				
r = 3.5%	$9,901	$9,509	$9,035	$8,151
r = 5.0%	$9,899	$9,490	$8,975	$7,975
r = 7.5%	$9,897	$9,462	$8,889	$7,749

computed for each alternative the amount required today to assure the $10,000 for abandonment, as shown in Exhibit D-3.

3. DETERMINATION OF THE COMPARATIVE COSTS OF THE ALTERNATIVES

We assumed that the costs associated with a financial statement constituted the baseline, since operators routinely prepare such statements. Based on that assumption, we determine the percentage increase of each of the other alternatives over the baseline.

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